The Dissertation Committee for Ian Alexander Partridge Certifies that this is the approved version of the following dissertation:

Potential contribution of a carbon offset scheme to the costs of greenhouse gas emissions reductions in developing countries

Committee:

Shama Gamkhar, Co-Supervisor

Charles Groat, Co-Supervisor

Ross Baldick

Michael Webber

Varun Rai

Potential contribution of a carbon offset scheme to the costs of greenhouse gas emissions reductions in developing countries

by

Ian Alexander Partridge, B.A. Honours; M.S. Man.

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Potential contribution of a carbon offset scheme to the costs of greenhouse gas emissions reductions in developing countries

Ian Alexander Partridge; PhD.

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Co-Supervisors: Shama Gamkhar; Charles Groat

The energy sector in the developing world is expected to account for 27% of global emissions of greenhouse gases from fossil fuel combustion in 2035 – in 1990 it accounted for 7%. The increase is concentrated in rapidly growing countries in Asia that depend on coal for power generation. Maximizing electricity generation using renewable technologies in these countries provides an obvious approach to slowing global emissions growth.

A barrier to increased use of renewable generation is cost: financial incentives could help to increase its use in developing countries. The principal objective of this research is to examine the practicability and potential scale of an offset scheme aimed at providing this incentive.

Offset schemes have a poor reputation due to problems experienced with the Clean Development Mechanism (CDM). I identify the CDM's failure to ensure the additionality of projects as a key issue and propose an approach to the assessment of additionality specific to grid connected generation projects. I present case studies of wind and small hydro projects in China and India in which I calculate the marginal abatement cost of emissions cuts and use the new approach to additionality to draw conclusions regarding the eligibility of projects to receive offsets in some hypothetical future scheme. My

analysis shows that the proposed approach offers advantages over methodologies permitted by the CDM.

I analyze the supply and demand for credits from existing schemes during 2013-2020 and show that oversupply will continue to impact their price, removing any incentive for investment in renewable generation. Using an original approach based on IEA forecasts for the energy sector, I estimate the maximum availability of offsets from a post-2020 scheme based on renewable generation, and assess the potential global demand.

I conclude that a scheme of the type considered would be feasible; that the proposed approach to determination of additionality could ensure its environmental integrity; that the supply of offsets could be managed to maintain the level of incentive for investment in renewables; and that a scheme of this nature would make a significant contribution to financing emission cuts in the developing world.

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PART 1: ANALYSIS AND RESULTS

1: Introduction

The process of international negotiations and action against climate change that began at Rio de Janeiro in 1992 crashed and burned at Copenhagen in 2009. Most delegates at Copenhagen believed that their role was to agree on the next stage of an ongoing process, following a roadmap agreed at Bali in 2007. Instead, the communiqué issued at the end of the conference was dictated by a few countries that did not want to follow the Bali roadmap and grudgingly accepted by the others. It mentioned some ideas that came out of Bali – such as NAMAs and New Market Mechanisms (these terms are explained in section 2.5 – a list of acronyms and abbreviations can be found following the Appendix, at the end of this document). However the Copenhagen accord abandoned all pretence that the international community was following a clear timetable for the implementation of the Bali proposals.

The two years after Copenhagen, marked by the conferences at Cancún and Durban, saw strenuous efforts to get the negotiation process moving forward again. The outcome was an agreement reached at Durban to complete negotiations by 2015 on actions to be implemented by 2020. Agreement on a timetable is clearly a hopeful development - it might seem unconstructive to point out that the Bali roadmap created a similar negotiating process and a deadline for agreement – at Copenhagen in 2009.

Arguably the signs look better this time around, but some observers believe that the framework of global negotiations under the aegis of the United Nations Framework Agreement on Climate Change (UNFCCC) has run its course. A recent book by David Victor argues that the time has come to jettison the global approach altogether: progress on cutting emissions would be faster in a context of negotiations between small groups of countries with interests that complement each other (Victor, 2011).

It is at least questionable whether the approach based on global negotiations and global implementation of agreed solutions can be revived. However a more optimistic view of the Durban resolutions is that they accept that a solution to the climate change problem could evolve outside the UNFCCC process – the conference discussed a proposal to create a framework that would enable countries to design and implement their own approaches under decentralized governance. Greater acceptance of flexibility may prove to be the most important outcome of Durban. The overall objective of this dissertation is to contribute to discussion of how that flexibility should be used.

1.1: PRIORITIES FOR ACTION

Greenhouse gases (GHGs) include methane and various others in addition to CO_2: in 2004 about 77% of GHG emissions in terms of CO_2 equivalent – usually abbreviated to CO_2e[1] - were CO_2. Of the total volume of CO_2 emissions in 2009, about 91% were due to the combustion of fossil fuels and to cement production – the remaining 9% arose from the net impact of changed land use practices, forest clearing and forest growth (Friedlingstein et al., 2010). Coal consumed in power stations accounted for about 30% of that 91% - up from 24% in 1990 and expected[2] to grow to 31% by 2020 (IEA, 2011).

Table 1.1 shows that the increase in global CO_2 emissions has occurred entirely in the developing countries and is concentrated in two sectors – energy and transport. By 2035, emissions by the energy sector in the developing world will account for 27% of all CO_2 emissions from fossil fuel combustion – in 1990 they accounted for 7%. This is the

[1] CO_2 equivalent: the quantity of CO_2 that would have the same impact on climate as the quantity of the gas in question (during the 100 years after emission).

[2] The IEA's annual World Energy Outlook includes forecasts for the global energy sector based on a number of scenarios. These change from time to time, but the current version of the document (IEA, 2011) employs three: the Current Policies scenario assumes no change in the energy-related policies adopted by governments as of mid-2011; the New Policies scenario incorporates broad policy commitments that have been announced but not yet implemented; and the 450 scenario adds policy measures that, in the opinion of the IEA economists, would allow a 50% probability of limiting temperature increases due to global warming to 2°C. All IEA forecasts quoted in this research relate to the New Policies scenario unless stated otherwise.

largest share of any emissions category in table 1.1 (below) and the growth of 537% over the period is the highest growth rate of any sector.

Table 1.1: CO_2 emissions from fossil fuel combustion in 2035

(a) % of global total

	Devcos	Non-Devcos	World
Energy	27.0%	13.6%	40.6%
Transport	10.8%	12.7%	23.5%
International Bunkers			3.8%
Other	21.3%	10.8%	32.1%
Total	59.1%	37.1%	100%

(b) Growth 1990-2035

	Devcos	Non-Devcos	World
Energy	537%	(17%)	97%
Transport	432%	26%	94%
International Bunkers			127%
Other	165%	(29%)	38%
Total	313%	(11%)	74%

Notes: Devcos means developing countries; source of all data is (IEA, 2011), based on the IEA's New Policies scenario; totals may not add due to rounding.

Breaking the category down further, a few rapidly growing countries in Asia show an even faster growth rate of energy sector emissions. Countries such as China and India are not only experiencing rapid economic growth - they are also dependent on coal for power generation. During the period from 1990-2035, forecast emissions from coal fired power stations in China will increase by 740%: in India the expected increase is 600%; and corresponding emissions in the US will fall by 10% (IEA, 2011). Several other developing countries - South Africa and Indonesia, for example – also have high rates of economic growth and high dependence on coal for power generation.

In terms of climate change mitigation, coal fired electricity generation in the developing countries is the elephant in the room: it is getting increasingly difficult to ignore (though climate change negotiators up to and including Kyoto managed to ignore it). This research focuses on the scope for reducing emissions from coal fired generation in a small number of fast developing countries.

The economic achievements of India and China in recent years make it easy to forget that they are poor by world standards. They both give very high priority to economic development – particularly industrial development - and any realistic model of industrial development implies growth of electricity use. During 1990-2009, electricity generation increased by a factor of more than five in China and more than three in India: the increase in China was equal to total generation in the EU in 2009 (IEA, 2011).

Both India and China have large indigenous reserves of coal and existing energy policies in both countries are essentially based on meeting increases in electricity demand by burning more coal. Even if the effect on global warming is ignored, this policy is likely to lead to problems. Coal fired plants emit damaging pollutants and use large volumes of water for cooling - the latter is a particular problem in Northern China. The economic impact of large-scale coal imports raises further issues, at least in India, where domestic output seems to have reached a plateau, leaving more expensive imports as the country's marginal energy source. Chinese mines have so far kept pace with demand, though domestic coal production cannot be increased indefinitely and China is no longer a major coal exporter. These concerns about the domestic impacts of coal burning together with international concerns about climate change create a shared interest in increasing investment in low carbon generation.

Potentially, this could be achieved by means of technological fixes such as nuclear power or "clean coal" – efficient coal fired generation with carbon capture and sequestration (CCS). Another possibility is natural gas, which emits half the CO_2 of coal per unit of electricity generated. In section 4.2.1 I discuss the possibility of either nuclear power or unconventional gas as solutions to Chinese and Indian emissions problems. I conclude that these are long term prospects, at best: in the short term, the best option for cutting emissions from power generation seems to be renewable energy.

At this point the problem becomes one of cost: the conventional wisdom holds that electricity from renewables is more expensive than electricity from coal, and developing countries are less able to pay. Its costs are also heavily front end loaded - in India in 2009, the initial investment cost per MW of wind generation was almost 70% higher than the cost of a coal fired power station (figures from generation cost model – see Chapter 4). These economic problems could be alleviated by a scheme or schemes that would channel funds to the developing world to incentivize the use of renewable generation by covering at least part of the added cost. In this research I analyze the practicability and potential effect of a scheme of this nature.

1.2: Funding proposals – the Green Carbon Fund and market based mechanisms

The climate change summit at Durban in 2011 agreed to initiate negotiations aimed at reaching agreement on further actions by 2015. The intended agreement will build on decisions made at past climate change conferences, which means that some of its key components can already be discerned, at least in outline. In particular, the agreement will recognize that the developing countries will take actions to reduce their greenhouse gas (GHG) emissions[3] and the developed world will partly finance these efforts.

The proposed financing mechanism is a Green Carbon Fund (GCF) that will have access to up to $100bn per year of funding. Spending on this scale would be decidedly ambitious: the closest institutional parallel to the proposed fund is the UN's Global Environmental Facility (GEF), which claims to be the largest provider of grant finance for

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[3] But will probably not accept hard targets for reductions and international monitoring of the results achieved.

environmental projects. Grant expenditure by the GEF is expected to reach $1bn per year during the current round of spending – 1% of the size of the proposed GCF. Financing provided through the Clean Development Mechanism (CDM) amounts to about $2.4bn per year (of which only part accrues to the host countries).[4] Turning to the private sector, $100bn is more than the combined annual capital spending of Exxon, Shell, Chevron and BP. It is hard to believe that any team of investment professionals could adequately evaluate spending proposals on this scale. Realistically, only a small part of the proposed funding can take the form of direct grants to fund specific projects - which leads to the question of how to utilize the rest of the available funds.

A clue to the answer is the provision in the Cancún agreement that foresees a significant role for new market-based mechanisms (NMMs). In this context, a NMM would mean some variation on an offsets scheme. An offsets scheme takes advantage of the fact that the cost of eliminating a given quantity of greenhouse gas emissions is not the same at every location. If a country – or a firm – has taken on an obligation to make cuts but finds that the cost of cutting emissions from its own facilities is high, it can cut emissions somewhere else where the cost is low and credit the cut against its own obligation. If the offsets scheme provides for trading of credits, it is possible to simply buy the credits corresponding to cuts that have been made by some other party. A key assumption that underlies the offset schemes described in this research is that it is cheaper to cut emissions in developing countries than in those with more advanced (and slower growing) economies. This is not always true (see, for example, (Sathaye and Phadke, 2006)), but it is normal and, in most cases, realistic to assume that the cuts are made in developing countries and the emitters with obligations to cut are located in the developed world.

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[4] Credits issued since 2006, annualized and valued at $15 per ton of CO_2e. Expected annual issuance between 2013 and 2020 by projects currently registered, also valued at $15, would be $13.1bn (though the oversupply discussed in Chapter 5 makes $15 seem somewhat optimistic).

The theoretical advantages of market based approaches have been described by economists (Coase, 1960; Montgomery W D, 1972). They also have political advantages: David Victor believes that private sector funds for GHG mitigation brought in via an offset scheme are likely to be more reliable than government to government funding, which he doubts will ever approach the level of $100bn per year proposed at Copenhagen. He sees the fundamental political logic behind the CDM (and, presumably, its successors) as moving the cost of resource transfers off government budgets. He believes that private firms have the strongest incentive to make a scheme that offers low-cost emission controls actually work, and have the best information on how to cut emissions at the least cost. In future, in Victor's view, most resources for emission controls in developing countries will flow through offset mechanisms (Victor, 2011).

Offset schemes do not cut emissions: their net effect is to ensure that cuts are made where the cost is lowest, thus saving money for their participants. It follows that, if those emissions reductions were going to be made anyway, with or without the scheme, the issue of offset credits actually increases global emissions. There is a net increase when the buyer of the credits does not make cuts that would otherwise be required as he is able to use the credits for compliance (Fischer, 2005). To ensure that this does not happen, the emissions reductions for which credits are awarded must be additional: this means that they would not have happened if the project had not received a subsidy in the shape of marketable credits (Fischer, 2005). Many researchers believe that the largest existing GHG offsets scheme – the Clean Development Mechanism (CDM) issues credits to many projects that are not additional.

1.3: KEY RESEARCH QUESTIONS AND OUTLINE OF DISSERTATION

The research presented in this dissertation is based on two propositions: firstly, that a scheme that provided financial incentives for investment in renewable generation in developing countries that are currently reliant on coal could make a significant contribution to cutting global GHG emissions; and secondly that an offsets scheme could potentially be the most effective approach to providing these incentives. The two principal elements of the research are a “bottom up” analysis of renewable generation projects in China and India, aimed at clarifying how they might fit into an incentives scheme; and a “top down” study of the potential scale of the scheme. A subsidiary element of the research is a review of criticisms that have been made of the CDM and an exploration of a possible approach to assessment of project additionality that would be more effective than methods used in assessing CDM projects.

In sections 1.1 and 1.2 above I identify coal fired electricity generation in a small number of rapidly developing countries as one of the largest and fastest growing sources of greenhouse gas emissions. I find that, in the short term, maximizing the use of renewable generation in these countries offers an obvious approach to cutting – or at least, sharply reducing the growth rate – of global emissions; and I suggest that a major barrier to increased use of renewable generation is the additional cost compared to coal. This cost disadvantage could be mitigated by a scheme designed to incentivize the use of renewable generation in the developing world.

In section 1.2 I point to the advantages – both theoretical and political – of an offset scheme as a means of achieving this objective: however offset schemes suffer from a reputation problem: the only significant carbon offsets scheme that has been implemented to date – the CDM - has been severely criticized. In Chapter 2 of this research I describe the CDM and provide an overview of the institutions – international bodies, offset schemes, emission trading schemes and funds – of which it is a part. In Chapter 3 I review criticisms of the CDM by other researchers and outline proposals that have been made for changes to the scheme – or its replacement. In my conclusions to Chapter 3 I draw on that analysis to identify conditions that should be met by a hypothetical future offset scheme intended to channel funds to the developing world to incentivize the use of renewable generation.

In Chapter 4 I present case studies of renewable generation projects in China and India and analyze empirically the suitability of different types of project for incorporation into a hypothetical sector specific offset scheme. Concluding Chapter 4, I use this analysis to add focus to the list of design parameters for a future offset scheme that concludes Chapter 3. Chapter 4 includes details of a proposed methodology for determination of additionality that offers advantages in the context of a sector specific scheme focused on electricity generation.

Chapter 5 comprises two separate analyses of the future supply and demand for offsets. I look first at the situation during 2013-2020. During this period, which coincides with phase 3 of the EU ETS – the EU's emissions trading scheme - offset supply and demand are likely to be dominated by currently existing schemes. My analysis quantifies the serious oversupply of offsets that is building up as phase 2 of the EU ETS comes to an end. This oversupply is linked to design issues with the CDM but linked also to the lack of flexibility of existing schemes when facing a changed economic situation.

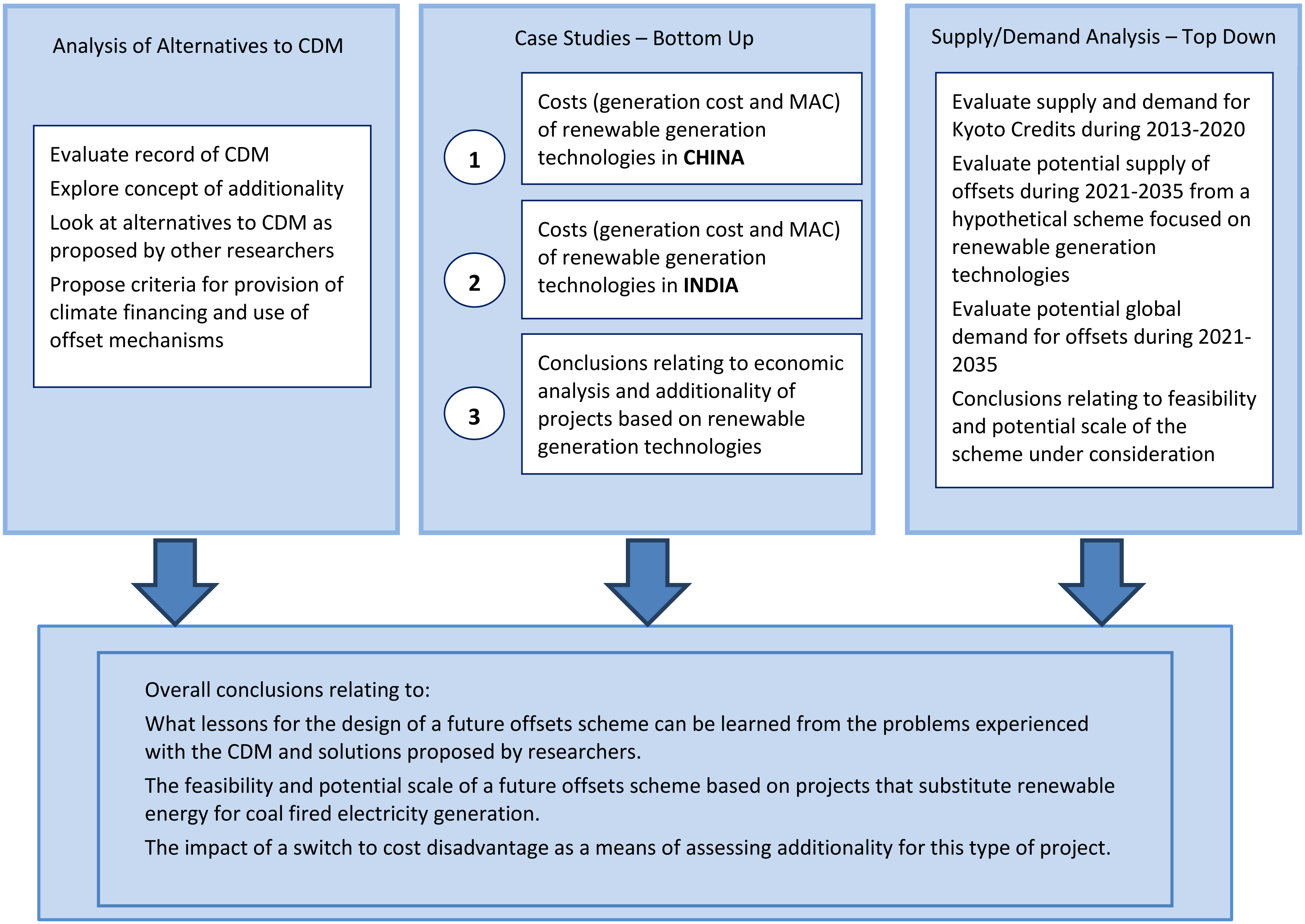
The second part of Chapter 5 presents a completely new analysis of the potential scale of a hypothetical offsets scheme that would operate during the period 2021-2035 and would cover only projects that substitute electricity generated using renewable technologies for electricity generated from coal. Also in Chapter 5 I present a forecast of potential demand for offsets from developed countries during that period. My supply and demand forecasts for 2021-2035 are based on projections of emissions reductions and electricity generated by type of technology taken from the IEA's World Energy Outlook (IEA, 2011). I show that an offsets scheme of the type envisaged is feasible and that it could be designed and managed to match offset supply to likely demand.

Chapter 6 presents my overall conclusions. Chart 1.1 provides an overview of the dissertation structure.

The research presented here appears to be unique in its scope. The prior research reviewed in Chapter 3 points out problems that have been encountered with the CDM and reviews some proposals that have been made for changes to the scheme or for new schemes that might replace it. These proposals are valuable contributions to debate, but in no case has an attempt been made at quantification of their impact on either emissions or on investment in developing countries. The combination in this research of a bottom up evaluation of actual projects with a top-down analysis of possible future schemes does not seem to have been attempted before: it enables me to put forward quantified suggestions as to how supply and demand might be managed in a possible future offsets scheme.

A list of acronyms and abbreviations can be found following the Appendix, at the end of this document.

Chart 1.1: Overall Structure of Dissertation



1.4: SUMMARY OF CONCLUSIONS

As noted above, my dissertation research focuses on how a hypothetical future offset scheme might be designed to channel funds to the developing world to incentivize the use of renewable generation. It asks how such a scheme could avoid the problems encountered with the CDM; it examines types of renewable energy project to consider how they might fit into such a scheme; and it assesses the scale of the contribution that the scheme could make to financing renewable generation in the developing world.

I conclude that it would be feasible to design such a scheme. I estimate that it could cut GHG emissions by roughly 0.5 bn tons per year. The offsets generated could amount to roughly double what the CDM has provided per year since 1/1/2010 (this is a maximum level that is unlikely to be reached). At an offset price of $20 per ton, the revenue generated by the scheme could amount to up to $10bn per year.

I propose an approach to the assessment of additionality based on comparison of generation costs and show that certain types of project that are strongly represented in the CDM should not be seen as additional. An incidental benefit of the proposed methodology is to emphasize that additionality should be seen as a dynamic concept – a project's additionality is affected by rapidly varying parameters such as input prices and parameters that change more slowly such as the effect of experience of a new technology in bringing down costs. Methodologies used in assessing the additionality of CDM projects are essentially static. In the specific context of grid-connected generation projects, the proposed methodology is clearly superior to those currently in use.

A key conclusion of my research is that it is necessary to manage an offset scheme to ensure a reasonable balance of supply and demand and avoid the price collapse experienced by the CDM. I show that this requirement could be incorporated into the scheme's initial design: maintenance of the necessary balance would require periodic reviews of the scheme's operations – a feature that is missing from the CDM.

2: Carbon Finance – the Institutional Architecture

The Kyoto Protocol, agreed at the Kyoto climate summit in 1997, grew more or less logically from a series of conferences that began with negotiation of the United Nations Framework Convention on Climate Change (UNFCCC), signed in 1992. Kyoto created a structure of mandates, requirements and flexibility mechanisms that was undoubtedly complex but was at least coherent: its elements were designed to work together to reduce global emissions of greenhouse gases in the least painful manner. This rationally designed structure began to buckle almost immediately, with the decision of the most important participant – the US – not to ratify. As the rest of the world implemented the elements of Kyoto, problems appeared and were dealt with through modifications to the original structure. Chapter 3 provides an analysis of problems encountered with the CDM, in particular, due to its importance to the subject matter of this research. (The Clean Development Mechanism (CDM) is described below. Climate negotiators love acronyms – a comprehensive list is provided at the end of the dissertation).

The period during which ratifying countries are obliged to comply with Kyoto ends in December 2012: long before that, successive climate summits were discussing the next stage. Various documents have emerged from this process: road maps; outlines; timetables (usually ignored); agreements to agree and so on. By now – only months before the Kyoto period finishes – discussions are continuing within a framework set by an agreement to agree by 2015 on a scheme to be implemented in 2020.

The structure of agreements and proposals described in this dissertation was never simple and has long since lost its basic coherence. It comprises the institutions and schemes created by Kyoto (and the conferences that preceded it); the patches that were applied as problems appeared; and the proposals that have been made for the future. In this Chapter I set out to describe and make sense of that framework, and to understand its strengths and weaknesses.

2.1: The UNFCCC and the Kyoto Protocol

In 1988, the World Meteorological Organization and the United Nations Environment Program set up the Intergovernmental Panel on Climate Change – the IPCC. A resolution of the General Assembly of the UN stated that the initial task of the new body was "to provide internationally coordinated scientific assessments of the magnitude, timing and potential environmental and socio-economic impact of climate change and realistic response strategies".[5]

The IPCC produces periodic Assessment Reports on "the causes, impacts and possible responses" to climate change. The first Assessment Report, published in 1990, was the basis for the negotiation of the United Nations Framework Convention on Climate Change (UNFCCC) which was adopted in May 1992 and signed by 154 nations (plus the EU) in June 1992, in Rio de Janeiro. It came into force in March 1994 after receiving the required number of ratifications. Since then, the principal forum for global negotiations on climate change has been the annual Conference of the Parties (COP) of the UNFCCC.

The third of these conferences (known in the jargon as COP3 – the third conference of the parties), held at Kyoto in 1997, adopted the Kyoto Protocol, which came into force on February 16, 2005: as of September 2011 it has been ratified by 191 nations plus the EU. Of the original signatories, only the US has failed to ratify.[6] The Kyoto Protocol commits the developed countries to reduce their emissions of six key greenhouse gases (GHGs) by at least 5% from 1990 levels during 2008-2012 - this amounts to a roughly 20% cut from the expected business as usual level of emissions for that period.[7] The

[5] http://www.un.org/documents/ga/res/43/a43r053.htm (accessed July 18 2012).

[6] Canada ratified Kyoto but officially withdrew its ratification in December 2011. Apart from the US, UN member states that have not ratified Kyoto, according to Wikipedia, are Afghanistan, Andorra and South Sudan.

[7] At least, it did at the time the Kyoto Protocol was adopted. The sharp reduction in growth due to the financial crisis will have much reduced the expected "business as usual" emissions level.

reductions are stated as CO_2 equivalent (CO_2e): for example, methane has a CO_2 equivalent (or global warming potential) of 25, meaning that the effect on the world's climate of a ton of methane over the first hundred years after it is emitted is the same as 25 tons of CO_2. Not all countries have accepted the same reductions: the EU as a group, for example, will reduce its emissions by 8%.

Annex 1 to the UNFCCC lists the developed countries and countries with economies in transition (the latter are mostly ex-communist states) while Annex B to the Kyoto Protocol lists the emission reductions agreed to by the developed countries. Confusingly, the two lists are not the same: Annex 1 (as amended in 1998) lists 40 countries plus the EU while Annex B lists 38 countries plus the EU, omitting Turkey and Belarus. The distinction is outdated – at least three non-Annex 1 countries (China, Korea and Mexico) intend to set a limit to their GHG emissions in the near future. However in this research I will follow common practice and refer to the developed countries generally as Annex 1 countries, using the term Annex B for discussion of the provisions of the Kyoto Protocol.

2.2: THE KYOTO FLEXIBILITY MECHANISMS: EMISSIONS TRADING

The cost per ton of reducing CO_2 emissions is likely to vary from place to place. The three flexibility mechanisms in the Kyoto Protocol allow cuts to be made where the cost is the lowest, thus reducing the aggregate cost of reductions to the Annex B economies. The first Kyoto flexibility mechanism is emissions trading: article 17 of the Protocol creates a legal framework for countries with obligations to cut GHG emissions to trade these obligations among themselves. The other two are both offset schemes: the Clean Development Mechanism (CDM) and Joint Implementation (JI). An offset scheme is a framework for any party with an obligation to cut GHG emissions to fund a project that cuts emissions elsewhere and credit the cuts against its own target.

Article 17 envisages trading at several levels. The Kyoto emissions caps are stated in Assigned Amount Units (AAUs): countries may trade AAUs; they may also trade Removal Units (RMUs) – i.e. quantities of CO_2 removed from the atmosphere by land use, land use change and forestry (LULUCF) activities; also Emission Reduction Units (ERUs) and Certified Emission Reductions (CERs), which are reductions in GHG emissions achieved by JI and CDM activities respectively. The trading envisaged by Kyoto is between countries: the best known emissions trading scheme – the EU ETS – covers trading between emitters (primarily commercial firms) and is not strictly speaking a Kyoto flexibility mechanism.

2.2.1: Why emissions trading?

The rationale for emissions trading is that it enables emissions to be cut where it is cheapest to do so. Scheme participants that are able to reduce their emissions cheaply can make reductions over and above their caps and sell the surplus to participants that face higher costs: the net effect is to reduce the average cost of emission reductions. The intellectual roots of all market based approaches to dealing with the externalities inherent in industrial processes can be found in the work of R.H. Coase – see (Coase, 1960). During the 1960s and early 1970s several authors analyzed the pros and cons of markets in rights to pollute – for example a market in water pollution (biological oxygen demand) for the Delaware estuary suggested by Jacoby and Schaumburg.[8] The economic basis of such schemes was explored by Montgomery (1972), whose key conclusion was that "even in quite complex circumstances the market in licenses has an equilibrium which achieves externally given standards of environmental quality at least cost to the regulated industries" (Montgomery W D, 1972).

[8] Unpublished – referenced in Montgomery (1972).

A weakness of the cap & trade approach is that, because reductions are made where it is cheapest, it is possible that most will occur in a few regions, leaving other regions as badly polluted as before. This is the problem that has effectively sunk the US Clean Air Interstate Rule (CAIR) and with it the market in SO_2 emissions initially created by Title IV of the 1990 Clean Air Act Amendments. A court held[9] that CAIR created a risk that some areas of the country could remain heavily polluted while others were cleaned up, and that this was inequitable and contravened existing law. It is ironic that emissions trading was included in Kyoto largely at the insistence of the US, which promoted the cap & trade approach because of the success of the SO_2 trading scheme.

The court's finding was foreshadowed by Montgomery (1972), which considered two forms of market: emission licenses, granting the right to emit a pollutant at a given rate, and pollution licenses, granting the right to cause a defined level (e.g. ambient concentration) of pollution at a given point. In a system of emission licenses, a market transaction that transfers emission rights from one source to another results in changes in pollution levels at all monitoring points, because emissions from the two sources would typically have different impacts at the various locations. An increase in pollution at a location already badly affected might be seen as inequitable – which is the issue that sank CAIR. Montgomery showed that a system of pollution licenses could ensure equity, but each emitter would have to hold a portfolio of permits covering all locations affected by its emissions – this would be impossibly complex if the objective were to control pollution over a wide area (Montgomery W D, 1972).

The brief history of CAIR contains two lessons for the carbon markets: the first is that the problem of concentration of pollution does not apply to CO_2 emissions, which affect the global climate – they have essentially no local pollution impact. The second lesson is

[9] The judgment of the Court is at http://www.epa.gov/cair/pdfs/05-1244-1127017.pdf (accessed July 18 2012). See also article in the *Wall Street Journal* dated July 12, 2010 (http://online.wsj.com/article/SB10001424052748704258604575360821005676554.html?KEYWORDS=CLEAN+AIR)

that, taking a closer look, it is clear that the SO_2 trading scheme had collapsed before the Court voided CAIR. The price of SO_2 emissions permits, which had peaked at $1,600 in 2005, had fallen to $3 by the time the *Wall Street Journal* published the story mentioned earlier. The collapse seems to have been due to over-allocation of permits, in part because the financial crisis had cut economic activity, reducing the BAU emissions level. It may also have been partly due to changes in technology as the US electricity generation sector switched from coal to natural gas. Those problems are certainly relevant to experience with the CO_2 markets.

2.2.2: The EU ETS

To the extent that there is a global price of carbon it is set by the European Union's Emission Trading Scheme (the EU ETS), which in 2010 accounted for 97% of all carbon trading globally (World Bank, 2011). The scheme was set up on October 13, 2003 by the EU's Directive 2003/87/EC and started operating in 2005. Its first phase, from 2005-2007, was intended to test the concept and the practicalities of trading mechanisms. The emissions cuts targeted in this phase were deliberately unambitious. The second phase was the Kyoto commitment period itself (2008-2012): the overall emissions cap for phase 2 was the level agreed by the EU at Kyoto, but individual countries' commitments were redistributed to take account of current circumstances. For example, the situations of the ex-communist EU members had changed radically with the fall of communism and the collapse of much of their heavy industry. With the Kyoto compliance period ending in 2012 and no successor in sight, the EU has unilaterally set targets for a third phase of the scheme, to run to 2020 and agreed outline arrangements for the period beyond 2020. By the end of phase 3 the EU countries will have reduced their emissions by 20% from 1990 levels.

Emissions caps are implemented by issuing EUAs (EU Allowances): one EUA confers the right to emit one ton of CO_2. For phase 3 this will become one ton of CO_2 equivalent as the scheme will cover other GHGs (N_2O emissions from the production of nitric, adipic and glyocalic acid and perfluorocarbons from the aluminium sector).[10] EUAs are registered securities - initial allocations and changes in ownership are recorded. For phase 1, practically all permits were allocated to EU firms for free, as were about 90% of permits for phase 2. In 2013 – the first year of phase 3 - at least 20% will be auctioned: this will rise to 70% by 2020 and it is intended that all permits will be auctioned by 2027.[11] The allocation process has evolved: for phase 1 the EU Commission – the central bureaucracy of the EU – effectively accepted caps proposed by the member states; for phase 2 it questioned and modified national proposals; for the third phase it made the allocation itself, based on detailed sectoral benchmarks.

By the end of April each year, firms that participate in the scheme must post audited reports of their emissions during the previous year and produce an equivalent number of permits. The EUA allocation for the current year is distributed in February: current year EUAs can be used to meet the previous year's compliance obligation – this is known as borrowing EUAs. Starting with phase 2, permits may also be banked – a surplus of permits may be carried over to succeeding years. Once delivered for compliance, the permits are cancelled and (at least for the Kyoto compliance period), information is passed to the UNFCCC, which cancels a corresponding number of AAUs.

A major change in the scheme is its expansion from January 1 2012 to cover aviation. CO_2 emissions from aviation account for about 3% of all EU emissions of GHGs; however the impact on global warming is roughly doubled due to the effect of contrails and of other gases.[12] All flights that arrive at or depart from an airport in the EU will have to

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[10] During the current phase of the ETS individual countries have been able to opt in their emissions of other gases: the Netherlands has elected to opt in its emissions of N_2O.

[11] Some industries that might be impacted by imports from outside the EU will receive free allocations covering a large part of their emissions. This provision is not subject to any termination date but will be reviewed in 2012.

[12] http://ec.europa.eu/clima/policies/transport/aviation/faq_en.htm (accessed July 12 2012).

produce permits to cover the whole length of the flight – not just the miles flown in EU airspace. It is not clear that the EU has the right under international law to charge non-EU airlines for miles flown outside EU airspace, however so far, no attempt to raise legal obstacles to the proposal has succeeded. The EU intends to bring emissions from the maritime transport sector into the ETS, though neither the method nor the timetable for this has been clarified.

The prices of EUAs have been highly volatile, partly due to the problems that the EU experienced in setting appropriate caps. In the first phase, the EUA price initially rose to €32.9 per ton,[13] and then collapsed when it became clear that the caps had been set too high. The caps were tightened for the second phase, but the unforeseen fall in EU GDP resulting from the financial crisis has reduced actual emissions, so the phase 2 caps are again too high. Cynics suggest that caps have been so consistently loose that the ETS has had no effect on European firms' emissions – this is probably too harsh a view, but certainly the EU ETS has yet to be tested under fire.

2.2.3: Other GHG emissions trading schemes

The EU ETS is not the only GHG emissions trading scheme operating today, though it is by far the largest, accounting for around 97% of all trading of emissions permits and offsets in 2010 (World Bank, 2011). A number of other schemes exist and may grow in importance in the future:

North America: Although there is no near term prospect of a national scheme being introduced in the US, two regional schemes are operating:

- A group of states in the Northeast (initially ten states, but New Jersey has withdrawn) have operated the Regional Greenhouse Gas Initiative (RGGI) – see

[13] Price of futures for December 2009 delivery.

http://www.rggi.org/ - since January 1, 2009. The scheme applies to CO_2 emissions from the power sector only.

The RGGI has suffered since its inception from serious over allocation, primarily because caps are based on 2002-2004 emissions: since that period a significant proportion of US generation has switched from coal to natural gas, and nuclear and renewables have made inroads. There are no plans to change the approach. Auctions are held quarterly but are something of a formality as the clearing price throughout the last two years has been equal to the floor price set by the scheme (currently $1.93 per ton of CO_2: the most recent auction was on June 6, 2012).

Offsets generated by projects in a few selected sectors, located in the RGGI states themselves, are eligible for compliance subject to a ceiling of 3.3% of the total compliance requirement.

- The second North American regional scheme – the **Western Climate Initiative (WCI)** – see http://www.westernclimateinitiative.org - will operate from January 1 2013. Member states will set up independent cap & trade schemes following a common set of standards. Several of the original members have withdrawn - currently it looks as if the scheme will commence operations with only California and four Canadian provinces – British Columbia, Ontario, Manitoba and Quebec. California and Quebec will participate from the start, with the other provinces joining later.

  Carbon leakage (i.e. the replacement of power generated within the state by power imported from a state that is not a participant in the scheme) is a major concern for both California and the RGGI states. It is less of an issue for Quebec, which is a major generator of hydro power. California includes emissions originating from imported power in its scheme – this might create problems if the courts interpret the rule as an attempt by California to regulate activities in other states.

New Zealand: Until July 1 2012, when the Australian scheme came into force, the New Zealand ETS[14] was the only national level mandatory scheme outside the EU. In its current form it has effectively been operational for the forestry sector since 2008, with transport, power generation and most industrial processes included since 2010 and other sectors being brought into the scheme later. The scheme does not impose an absolute cap on emissions: instead, units (called NZUs) are issued free to most sectors on an intensity basis – i.e. a set number of NZUs per unit of sector output based on an assumed level of emissions intensity. The allocation rate will reduce over time, starting in 2013. Scheme participants with emissions in excess of their free allocations must purchase additional units – either NZUs, which will be sold by the government, initially at a fixed price of NZ$12.50 per ton of emissions, or Kyoto Credits (CERs or ERUs). The fixed price for additional NZUs was intended to set a cap on prices, however the recent fall in the price of CERs means that, above the free allocation limit, it is now cheaper to rely on Kyoto units, which are accepted subject to the same restriction on industrial gas projects as the EU ETS. Unlike the EU ETS, the New Zealand scheme accepts RMUs.

The scheme has a strong focus on forestry. Owners of forests planted since 1989 receive NZUs for the increase in carbon sequestered in their forests but must produce NZUs when sequestered carbon is reduced by harvesting. There is a simpler scheme for owners of pre-1990 forest land. When agriculture is brought into the scheme in 2015 it will be the only scheme in the world that covers the agricultural sector.

Australia: A bill passed by the Australian Senate[15] in November 2011 paved the way for carbon pricing, with 500 of the country's largest emitters required to present permits for their emissions from July 2012. Initial allocations to some sectors will be free, with others obliged to purchase units at a price that is initially fixed at A$23 (US$24) per ton

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[14] http://www.climatechange.govt.nz/emissions-trading-scheme/ (accessed July 12 2012).

[15] http://www.cleanenergyfuture.gov.au/ (accessed July 12 2012).

of CO_2e (effectively a carbon tax), and will escalate at 2.5% per year. In 2015 the scheme will transition to cap & trade, operating on a market basis with controls on prices that will be removed in 2018. The extent of reductions targeted by the scheme will depend on the degree of effort made by other countries, with an unconditional commitment to at least 5% below 2000 levels by 2020. Two existing Australian carbon trading schemes – in New South Wales and the Australian Capital Territory – were terminated as of July 2012 when national carbon pricing took effect (the New South Wales scheme had the distinction of being the world's first CO_2 cap & trade scheme).

Switzerland: Switzerland operates a semi-voluntary carbon trading scheme (firms may participate as an alternative to paying a carbon tax). The Swiss government is considering making the scheme mandatory and negotiations to link the Swiss and the EU schemes have been ongoing since 2010 – a recent government announcement indicated that this could happen from 2014.

Japan: Japan has several voluntary schemes in operation: the most important are the Japan Voluntary Emissions Trading Scheme (JVETS), which sets absolute caps on CO_2 emissions; a scheme set up by the Keidanren (organization of the major Japanese industries), which sets intensity targets and tends to attract high emitters as voluntary participants (Kimura and Tuerk, 2008); and a scheme covering the Tokyo metropolitan area. The Japanese government seems to have abandoned plans to introduce a mandatory national emissions trading scheme, partly due to the disruption to its energy markets following the Fukushima nuclear disaster. Reports in Australian newspapers during February 2012 cited comments by Japanese diplomats that carbon pricing could not be considered in current circumstances. A press report dated June 1 2012[16] quoting Deputy Prime Minister Katsuya Okada stated that Japan may set new emissions targets – officially it intends to cut emissions to 25% below 1990 levels by 2020.

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[16] http://www.japantimes.co.jp/text/nn20120601a7.html (accessed July 18 2012).

The voluntary markets: Voluntary markets are a small but important component of the overall carbon market. Their primary role is to provide a market in which individuals and organizations can offset their personal carbon footprint – mostly via schemes such as those run by airlines ("check this box if you are a good citizen and want to offset the emissions caused by your flight!")

In 2011 the voluntary markets saw a record transaction volume of $569m, though this was still no more than 0.3% of the global carbon market. Reports indicate this includes some so-called "pre-compliance" buying by organizations interested in the WCI cap and trade scheme that is now due to start operating in 2013. Pre-compliance buying accounts for large purchases of forestry-related offsets that are not eligible for the EU ETS but will be accepted in the WCI (World Bank, 2012).

The voluntary markets have encouraged the creation of a small parallel universe of organizations that assess and certify offset projects – essentially doing the same job as the CDM Executive Board but (they would argue) with greater flexibility and less bureaucracy. The largest of these in volume terms is the US-based Verified Carbon Standard (VCS) – http://www.v-c-s.org/. The Gold Standard seal of approval, which can also be granted to a CDM project (http://www.cdmgoldstandard.org/), provides additional assurance, particularly for buyers motivated by the contribution their purchase makes to sustainable development. Gold Standard projects seem to enjoy a price premium over others (World Bank, 2012). A voluntary cap & trade scheme run by the Chicago Climate Exchange folded during 2010, partly due to serious over-allocation that had cut prices to a few cents per ton (World Bank, 2011) – essentially all voluntary market transactions are now over the counter.

2.2.4: Carbon trading in non-Annex 1 countries

A few non-Annex 1 countries plan to introduce emissions trading schemes. **Korea** is likely to be the first, and will be the third country in the Far East (after Australia and

New Zealand) to introduce carbon trading. A bill mandating the creation of a Korean ETS passed its final legislative hurdles In May 2012: trading will start in 2015. In **Mexico**, the legislature passed a climate change law in April 2012 that sets legally binding (and notably ambitious) targets for emissions reductions and encourages the setting up of a national cap & trade scheme (apparently compliance would initially be voluntary). **Brazil** has stated an intention to introduce carbon trading: the state of Rio de Janeiro is setting up a state level scheme that will operate from 2013 and may serve as a pilot for a national scheme. The state of Acre has signed a memorandum of understanding with California and the Mexican state of Chiapas that allows for the implementation of forestry schemes and the generation of REDD+ credits (see list of acronyms and abbreviations at end of document) that will be eligible as offset credits in California's emissions trading scheme.

One of the more significant national emission promises announced after the Copenhagen conference was an unconditional commitment by **China** to reduce the emissions intensity of its economy to 40% - 45% below its 2005 level by 2020. Some critics have denounced the proposal as no more than business as usual but an analysis by Frank Jotzo shows that this is based on a BAU case that already includes strenuous efforts to cut emissions (Jotzo, 2011). It seems churlish to criticize the Chinese proposal, bearing in mind that the proposed absolute reduction from BAU is greater than the 2005-2020 reductions proposed by all developed countries combined (Jotzo, 2011).

A key element of China's plan to achieve this target will be a cap & trade scheme. The country's 12th five year plan (2011-2015) provided for carbon trading and in October 2011 the National Development and Reform Commission (NDRC) announced the introduction of pilot schemes in five cities and two provinces, together accounting for 18% of China's population and 28% of its GDP. NDRC officials have indicated that the plan is for these pilot projects to operate from 2013 with a view to establishing a national scheme in 2015 (World Bank, 2012). In January 2012 the Asian Development

Bank announced that it will provide both funding and assistance with design for a pilot scheme to be established in Tianjin – a municipal province - in 2013 (press release dated Jan 25, 2012 – see www.adb.org). In July 2012 the NDRC released outline regulations for the new markets, apparently closely modeled on the rules of the CDM and allowing explicitly for the use of offsets derived from CDM projects.

There is still some uncertainty about the details of China's scheme, which may be intentional – China agreed at the Durban climate conference to enter negotiations over an international agreement to control emissions and to reach an agreement by 2015: it may want to try out ideas without disclosing its real negotiating position. Other approaches to control of emissions have been mentioned – caps on energy use, for example. However a realistic appraisal of Chinese intentions would be that a national emissions trading scheme will be introduced – possibly by 2015, more likely by 2020 – if the pilot schemes show that the idea is workable in Chinese circumstances.

2.3: THE KYOTO FLEXIBILITY MECHANISMS: CARBON OFFSETS

The Kyoto Protocol's flexibility mechanisms include two different offset schemes: the Clean Development Mechanism (CDM) and Joint Implementation (JI). Under the CDM an Annex B nation may create offsets by financing emissions reductions in a developing country; under JI, offsets can be created by financing reductions in another industrialized country. In practice, most JI projects are located in countries with economies in transition – this means primarily the ex-communist countries.

The Kyoto Protocol also provides for crediting of volumes of CO_2 removed from the atmosphere by absorption in soil and vegetation, by means of measures coming under the general category of LULUCF – land use, land use change and forestry. Although it is not usually described as a Kyoto flexibility mechanism, Articles 3.3 and 3.4 of Kyoto permit a country to assess volumes of CO_2 removed in this way and either count these volumes as negative emissions in its compliance reporting or issue removal units (RMUs) that can be traded in the same way as CERs or ERUs. The RMU market has never taken off as the two better known flexibility mechanisms have: the direct cause of this failure is the EU's refusal to accept RMUs for compliance in its emission trading scheme: the underlying cause is probably a persistent lack of trust in the integrity of issuance procedures. However the first issues of RMUs were recorded in 2011, by France, Australia, Russia and Hungary; it seems likely that Hungary sold its RMUs to buyers in New Zealand – if confirmed, this would be the first sale of RMUs (World Bank, 2012).

2.3.1: The Clean Development Mechanism

The objectives of the CDM, which was created by Article 12 of the Kyoto Protocol, are (in the order in which they are stated in the text of Kyoto): to assist non-Annex 1 countries in achieving sustainable development; to "contribute to the ultimate objective of the convention"; and to cut the costs of emissions reductions in Annex B countries. It is not entirely clear what the second of those objectives means: some have interpreted it as putting the less developed countries onto a low carbon development path (Vasa and Neuhoff, 2011); my own view is that the ultimate objective of the convention is simply to reduce GHG emissions. It is possible that a lack of agreement on its objectives is one of the underlying reasons for the many criticisms of theCDM.

The Kyoto Protocol, signed in 1997, gave few details on how the CDM was to be implemented: these had to wait until COP7, held at Marrakech in 2001. The intervening years saw intense negotiations. According to Lecocq and Ambrosi, some stakeholders were suspicious of elements of Kyoto: in particular, some European parties distrusted the concept of flexibility mechanisms and, in some cases, the concept of markets (Lecocq and Ambrosi, 2007). Partly to placate these critics, the UNFCCC evolved a bureaucratic approach to CDM project assessment which has been criticized at various times for failing to adequately assess proposed projects and for assessing projects so thoroughly that a huge backlog built up, frustrating the objectives of the CDM. In section 3.1.2 I provide an outline of the process; sections 3.2.7 and 3.2.8 include some analysis of the problems that it has created – or at least has been blamed for.

Whatever the problems, demand for offsets emerged even before Marrakech: the Prototype Carbon Fund (PCF) - a $180m fund run by the World Bank that invests in CERs and ERUs – operated from 2000. The government of the Netherlands was also an early investor (Lecocq and Ambrosi, 2007). Large scale participation by private firms had to wait until governments that had ratified Kyoto had determined how they would achieve their targets – a key development was the acceptance of CERs for EU ETS compliance from 2005 under the "linking directive" (EU Directive 2004/101/EC). Almost all trading in CERs now occurs on markets linked in some way to the EU ETS (World Bank, 2011).

2.3.2: Joint Implementation

The second offset scheme created by the Kyoto Protocol is Joint Implementation, or JI. The JI program awards offsets to projects that reduce emissions of GHGs in Annex B countries - the offsets awarded are called Emission Reduction Units (ERUs) and can be traded and used for compliance in the same way as CERs. There are two alternative procedures for JI project validation and award of ERUs. The Track 1 procedure can be used by countries that have a national reporting system for GHG emissions, make annual returns of emissions and have set up a national registry for ERUs. Under the Track 1 procedure a country certifies emission reductions and issues ERUs in respect of projects in its own territory. Countries that do not meet the eligibility requirements can still set up JI projects but reductions must be certified by the JI Supervisory Committee of the UNFCCC. This is called the Track 2 procedure.

As an Annex B country, the host country of a JI project is subject to an emissions cap, must make an annual return of its emissions and must surrender the appropriate quantity of AAUs in the annual Kyoto compliance exercise. To avoid double counting of emissions cuts, it must surrender an AAU for each ERU it issues. As AAUs have been issued only for the Kyoto compliance period (2008-2012) and there is at present no prospect of international agreement on an extension, the validity of ERUs issued after the end of 2012 is questionable. The current situation is that post-2012 ERUs will not be accepted for compliance in the EU ETS but will count in determining national compliance under the Kyoto Protocol. As the "true-up period" for Kyoto lasts until mid-2015, there will be a limited ERU market until that date.

Most JI projects are located in Russia and the former communist countries of Eastern Europe (the "transition economies") however a few have been registered in New Zealand, France, Germany, Spain and Sweden (as of February 2012). JI projects in EU countries are subject to special rules designed to prevent double counting of emissions cuts by selling credits while simultaneously counting the reductions towards compliance with the host country's obligations under the EU schemes.

2.3.3: Offsets in the EU ETS

Participants in the EU ETS may meet their compliance obligations by delivering CERs or ERUs in lieu of EUAs. The use of offsets for compliance is subject to volume limits – the intention is that emission reductions made by the EU countries themselves should be the primary means of compliance. Despite these limits, the EU ETS is by far the most important market for carbon offsets: in 2011 the value of secondary market transactions in the CER market reached a global total of $22.3bn, almost all linked to the EU ETS. The volume of secondary ERU transactions in 2011 was $780m (World Bank, 2012).

Its dominance of the offsets market means that EU rules on eligibility of offsets for ETS compliance have a major impact on the CDM and JI schemes. The EU does not accept credits from nuclear power projects, nor projects in land use, land use change and forestry (LULUCF), while strict rules limit the use of credits from large hydro schemes. For phase 3 (2013-2020) the EU has made a number of changes in its rules for acceptance of offsets in the EU ETS, which have split the post-2012 CER market into EU ETS-eligible and ineligible sectors – see box below.

Changes in eligibility of offset credits for the EU ETS

The key changes, which take effect at the end of 2012, are: [17]

- **A lower limit on the total number of offsets** that can be used for compliance. The use of offsets was not permitted at all during the first phase; during phase 2 the limit is based on a set percentage (that varies by country) of average emissions during 2008-2012 – the overall limit is 1,419 Mt[18] (including a small volume in respect of aviation in 2012). Changes for the third phase, including small additional volumes in respect of sectors that were not covered by phase 2 of the scheme, increase the limit to 1,611 Mt. However this applies to phases 2 and 3 combined: whatever is not used in phase 2 can be carried forward to phase 3.
- **Changes in sector eligibility**. From 2013, emission reductions from projects that incinerate industrial gases (HFCs and N_2O) will not be accepted.[19] CERs from carbon capture and sequestration (CCS) projects can be opted in for phase 2 compliance: for phase 3 they are explicitly eligible.
- **Disallowance of most projects registered after 2012**. Kyoto Credits from any project (excluding industrial gas destruction projects) registered before the end of 2012 will be accepted for compliance during 2013-2020. However credits awarded to projects registered after that cut-off date will only be accepted if the project is located in countries on the UN list of least developed countries and small island developing states (referred to hereinafter as LDCs).
- **The effective end of the JI scheme**. Because the Kyoto Protocol requires that a valid AAU must be cancelled for each ERU issued to a JI project and AAUs are valid only for the Kyoto compliance period (2008-2012), the EU is somewhat pedantically taking the view that no more ERUs may be issued after the end of 2012.

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[17] See http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0136:0148:EN:PDF. Also http://ec.europa.eu/clima/policies/ets/linking/docs/q_a_20111114_en.pdf (accessed July 18 2012).

[18] Different analysts estimate slightly different figures – there is uncertainty about, for example, the status of sub-sectors that a country has included in its cap unilaterally.

[19] They can be used for 2012 compliance, which means until April 2013.

Possibly the most significant change is the disallowance of schemes that cut emissions of certain industrial gases. As these industrial gas projects account for 68% of all CERs issued to date, the result is a draconian reduction in availability of offsets for EU ETS compliance. However, this is not sufficient to ward off the buildup of a large surplus. In Chapter 5 I present an analysis of supply and demand for offsets post-2012: it shows a major imbalance, with very large and rapidly increasing supply and essentially fixed demand from the EU ETS and other schemes. Despite the changes in eligibility described above, even the ETS-eligible sector is in oversupply and offset prices have fallen to the point where the Kyoto flexibility mechanisms no longer provide a significant incentive for investment in GHG mitigation in the developing world. The EU is considering measures aimed at reducing this imbalance, including possibly withholding tranches of EUAs from the market, but no decisions have been taken.

2.4: EMISSIONS TRADING TODAY

Carbon trading has been one of the successes of the GHG mitigation architecture created by the Kyoto Protocol, very largely because of the success of the European Union's Emission Trading Scheme.[20] EU emissions allowances (EUAs) accounted for 84% by value of all global carbon trading in 2011 while the secondary market in CERs accounted for another 13% - almost all trading in CERs is linked to the EU ETS (World Bank, 2012). Several governments are active players in the carbon markets, in particular those of Japan and the EU countries (the EU ETS covers about 41% of all GHG emissions in the EU: governments have direct responsibility for the remaining 59%). Table 2.1 provides a summary of how carbon trading has grown over time.

[20] The EU ETS is a framework for trading between emitters while Kyoto allows for trading between countries, so strictly speaking the ETS is not a Kyoto flexibility mechanism.

Table 2.1: Global carbon market volumes 2004-2011 ($bn)

	EUAs	Primary CDM	Secondary CDM	Other Instruments	Total
2005	7.9	2.6	0.2	0.3	11.0
2006	24.4	5.8	0.4	0.6	31.2
2007	49.1	7.4	5.5	1.0	63.0
2008	100.5	6.5	26.3	1.8	135.1
2009	118.5	2.7	17.5	5.0	143.7
2010	133.6	2.7	20.5	2.4	159.2
2011	147.8	3.0	22.3	2.9	176.0

Source: (World Bank, 2011, 2012), based on various primary sources

Notes: The apparent increase from 2009 to 2010, particularly in EUA trading, reflects a change in methodology by the World Bank team.

These figures include both physical and derivatives trading. Most trading is in futures.

Most of this trading takes place in liquid markets in which financial sector regulators ensure price transparency. The futures markets accounted for 88% of EUA trading and 92% of secondary CER trading in 2011 (World Bank, 2012) - trading in options is also significant. About 90% of futures transactions are made on ICE Futures Europe, a London-based unit of the Intercontinental Exchange (New York), formerly known as the European Climate Exchange (World Bank, 2011). Part of the reason for the high proportion of derivative trading is that the spot markets have been tainted by fraud during the last two years (World Bank, 2012); an equally important reason is that there is no advantage in holding actual EUAs, which are used only once a year for compliance. In fact, there is an opportunity cost to holding them because in a spot transaction the full price must be paid immediately; futures may be held by meeting only the margin requirements (Daskalakis et al., 2010).

However not all trading occurs on transparent and regulated markets. About 43% of secondary market volumes are dealt over the counter at prices that are typically not reported,[21] while almost all transactions in the primary markets for CERs and ERUs result from deals made directly between project developers and market participants, again without price disclosure. Some information on prices for these transactions comes from organizations such as IDEAcarbon and Thomson Reuters Point Carbon, which assess prices based on contacts with market participants. The annual World Bank publication *State and Trends of the Carbon Market* collates information from these sources as well as its own market survey. The most recent edition states that prices achieved in 2011 for pre-2013 primary market CERs averaged €7.9 per ton, with CERs from post-2012 registered projects about 5% higher (World Bank, 2012). Uncertainty over prices reduces the value of studies of the CDM where the conclusions depend on the carbon price or on a value that implies a price, such as project revenues or rates of return. Often the "carbon price" comes from project documentation prepared before construction commences and some years before CERs are actually issued. One suspects that developers do not spend much time over this estimate as it seems to have no relevance to the registration process.

Price formation in the most important sectors of the carbon market is described below:

- A CDM project developer sells the expected stream of CERs forward, using the **primary CER market**. A primary sale is typically a fixed term contract to sell units at a pre-determined price. The purchaser bears significant risks: prices in this market vary considerably between deals, depending on the perceived risk of non-delivery and the expected volume of credits to be delivered before some deadline – for example, there has always been some uncertainty about the value of CERs post-2012. Contract terms may be drawn up to transfer more or less of this risk to the buyer (Lewis, 2010): some "sales" contracts are little more than options. Post-2012 risk has been reduced by the EU's decision to continue with the EU ETS until 2020;

[21] From *Bloomberg New Energy Finance* – quoted in *Carbon Finance Online* January 12, 2011.

however changes in the rules for EU ETS eligibility have fragmented the market (World Bank, 2011). Primary market volumes have fallen from a peak of $7.4bn in 2007 to $3.0bn in 2011 (World Bank, 2012).

- The **secondary market for EUAs and CERs** has been highly volatile. CERs are equivalent to EUAs for EU ETS compliance purposes and the CER price has typically tracked the EUA price, which reached a peak of €32.9 in April 2006.[22] However in April 2006, when the first hard data on 2005 emissions in the EU emerged, the price collapsed. Prices for futures for delivery during the second phase of the EU ETS later recovered to around €15 but fell again as the financial crisis cut economic activity. A recent phenomenon is a widening spread between EUA and CER prices linked to oversupply of CERs. As of July 18 2012 EUA futures (for delivery Dec 2012) are priced at €7.13 and CER futures at €2.96.
- The **ERU market** is similar to the CER market, but far smaller – secondary market volumes in 2011 amounted to $780m compared to $22.3bn for the secondary market in CERs (World Bank, 2012).
- The Kyoto Protocol emissions caps are implemented by issuing each Annex B country with AAUs: an AAU is a permit to emit one ton of CO_2e. Countries that emit less than their quota can sell the surplus in the **AAU market**. The ex-communist countries are the largest potential sellers as their caps were based on emissions in 1990 and the collapse of their heavy industry when communism fell left most of them with huge volumes of surplus AAUs (Aldrich and Koerner, 2012). In Ukraine, emissions declined by 60%. Den Elzen et al calculated that the surplus of AAUs in Eastern Europe and Russia amounted to 13bn tons. (den Elzen et al., 2010).

[22] Price of futures for December 2009 delivery.

Cynics refer to the AAU market as a market in hot air. The first AAU trade was in 2002 but most potential buyers seem to fear damage to their reputations if they achieve compliance by purchasing AAUs. In an effort to make AAU trades more respectable, selling countries may commit to spending the proceeds on green investment schemes (GISs) - projects that cut GHG emissions. A sale of AAUs linked to a GIS is known as a "greened" sale. However, there are no rules defining a GIS and no entity analogous to the CDM EB to determine whether claimed GHG reductions are real. It is not unknown for a selling country to agree to a greened sale then postpone investment in a GIS – according to media reports, the Hungarian government was reprimanded by the EU for using revenues earmarked for a GIS for general budgetary expenses (Tuerk et al., 2010).

However, as the Kyoto deadline approaches, some Annex B countries are becoming concerned about hitting their emissions targets. AAU trading stuttered into life - then collided head on with the financial crisis that weakened economies (and thus cut emissions) in many Annex B countries. A growing surplus of CERs now competes with AAUs that are hampered by skepticism about hot air and the dubious benefits of some GISs. Volumes of AAU sales are minimal: the "Other Instruments" column in table 2.1, mainly AAUs and ERUs, accounted for only 1.6% of the global carbon market in 2011.

The real significance of the AAU surplus is the fact that the Kyoto Protocol allows surplus AAUs to be banked for use in an anticipated second compliance period (Aldrich and Koerner, 2012). If the East European countries insist on the validity of their AAUs in a post-2020 climate deal, or if countries that made unilateral reduction commitments for 2012-2020 want to meet these commitments by using AAUs, the apparently moribund hot air market could come back to haunt climate negotiators.

2.5: From Bali to Durban – and beyond

The timetable set by the Kyoto Protocol extends only to the end of 2012. A second stage was always envisaged: detailed planning for "Kyoto 2" began at the conference –

known in the jargon as COP13 – held on the island of Bali in 2007. The summary document that emerged from Bali is known as the Bali road map: its key elements are included in the Bali Action Plan,[23] which launched a process based on a "shared vision for long term cooperative action". The Bali Action Plan included, in addition to quantified emission reductions by developed countries (as in Kyoto 1), several new proposals for actions on mitigation of carbon emissions. These proposals include "nationally appropriate mitigation actions" (NAMAs) by developing countries; action on deforestation and forest degradation; sector-specific actions; and new market-based approaches aimed at enhancing cost-effectiveness. In contrast to Kyoto 1, the Bali Plan proposed an increased focus on adaptation and technology transfer and contained enhanced proposals on availability of financial resources for both mitigation and adaptation. Finally, it created an Ad-Hoc Working Group on Long Term Cooperative Action under the Convention, charged with completing its work in time for COP15 (the Copenhagen climate conference in December 2009). It is not surprising that many countries came to Copenhagen believing that they were going to agree on a second stage of the Kyoto Protocol.

Judged against those expectations, Copenhagen failed, as did the two year process of negotiation that began at Bali. Taking a positive view, however, Copenhagen was the start point of a process that may lead to a comprehensive agreement on international action against climate change. The conference at Durban (COP 17; 2011) agreed to a process of negotiations leading to a binding agreement by 2015, to be implemented by 2020. Many elements of the Bali road map are very much alive and are likely to be included in the proposed agreement. Examples include:

- Nationally Appropriate Mitigation Actions (NAMAs). A NAMA is an action taken unilaterally by a developing country to cut GHG emissions. The UNFCCC proposes to

[23] http://unfccc.int/resource/docs/2007/cop13/eng/06a01.pdf

establish a registry for NAMAs seeking international support (World Bank, 2011). Proposals are still not finalized, but the intention is that the developing country will monitor progress and make periodic reports. Some post-Copenhagen commitments made by non-Annex 1 countries might become NAMAs. There is also potential overlap between NAMAs and future sectoral crediting mechanisms (section 3.3.3).

- New Market Based Mechanisms (NMMs). Agreement was reached at Cancún that one or more NMMs would form part of the future agreement (section 3.3.2).
- Action on a sectoral basis. As a minimum this means sectoral CDM (section 3.3.1).
- Action to mitigate GHG emissions from destruction of forests.
- The proposal first mooted at Bali for enhanced financial resources for mitigation and adaptation actions by developing countries is being actively developed (section 2.6).

However, some analysts have suggested that there may be flaws in the UNFCCC process that will doom the proposed negotiations to failure. This view gained traction after Copenhagen – more recently it was explored in a book by David Victor (Victor, 2011). Certainly, it is at least questionable whether the focus on solutions reached through global negotiations and global implementation of the agreed solutions can be revived. Victor's view is that significant elements of any solution to the climate change problem may evolve outside the UNFCCC process: in particular, he sees advantages in a diversity of offset schemes, with a form of competition between them to determine which set of rules works best. In my view, the outcome of the Durban conference signaled a degree of acceptance of this view. If I am right, this acceptance of flexibility may ultimately prove to be the most important outcome of Durban. However the hypothetical scheme considered in this dissertation is not contingent on a specific negotiating process.

2.6: THE UNFCCC REPORT ON CLIMATE CHANGE FINANCING

The Copenhagen Accord contains a commitment by the developed countries to provide "scaled up, new and additional, predictable and adequate" funding to the developing world to support action on both mitigation and adaptation. The level of funding agreed is up to $30bn for the period 2010-2012 and a commitment to mobilize $100bn per year by 2020. The funds will come from a variety of sources – public and private; bilateral and multilateral; and including "alternative sources of finance". A significant portion will flow through a new entity to be known as the "Copenhagen Green Climate Fund".[24]

Responding to this commitment, the Secretary-General of the UN established a "High-level Advisory Group on Climate Change Financing" which reported[25] to the Cancún conference (COP16) in 2010. There seems to have been some dissent within the group - some of the report's conclusions are couched in extremely cautious language, possibly to gloss over political differences. It is hard to think of a non-political explanation for the proposal of a financial transactions tax as a source of funding for climate change mitigation, for example. Another area where politics seems to have been involved is in assessing what proportion of a gross investment flow should be regarded as a net transfer to the developing world - an important issue, and one on which group members from developed and developing countries might legitimately have different views.

The report develops scenarios for potential future flows, based essentially on different levels of carbon price (these scenarios are very similar to the Current Policies, New Policies and 450 scenarios used by the IEA and described in Chapter 1). Most of the group's conclusions are based on the medium price scenario, which assumes full implementation of the pledges made after Copenhagen, with a carbon price in the range

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[24] See http://unfccc.int/resource/docs/2009/cop15/eng/11a01.pdf#page=3 for the text of the Copenhagen accord.

[25] http://www.un.org/wcm/content/site/climatechange/pages/financeadvisorygroup/pid/13300

of \$20-\$25 per ton of CO_2e in 2020. Estimates of potential revenues are expressed as ranges – often very wide – and the report notes that there is significant overlap – it would not be possible to implement all the proposals together. It concludes that realistic estimates of potential net revenues to developing countries in the medium price scenario would sum to \$80bn - \$90bn:

- Gross private sector capital flows of \$100bn-\$200bn per year might be generated, of which \$10bn-\$20bn could be regarded as net flows to the host countries.
- Carbon markets might generate \$30bn-\$50bn per year, of which possibly \$10bn could be regarded as net transfers to the developing world.
- A 10% share of revenues from carbon taxes levied by developed countries and on auctions of emissions allowances could potentially mobilize around \$30bn per year.
- Carbon pricing for international air and sea transportation would bring in about \$10bn per year, assuming that 25%-50% of revenues were earmarked for the fund.
- Up to \$10bn per year could be raised from other sources: examples given are the redeployment of fossil fuel subsidies in developed countries and a financial transaction tax.
- The multilateral development banks (MDBs) are able to multiply incremental investments. The group estimated that every \$10bn of additional funding to MDBs would result in investment of \$30bn-\$40bn, with associated private sector flows providing even more. Overall, net accruals to developing countries from investment by MDBs could reach \$11bn per year.

With additional sums provided by direct budget contributions, the task of raising \$100bn per year is described as "challenging but feasible". In an interesting aside, the group notes that the credibility of the countries concerned – from both the developed and developing worlds – would be greatly increased if there were confidence that the resources will be spent wisely.

2.6.1: The potential role of offset schemes

The report of the Advisory Group is backed up by the reports of sub-groups, of which the most interesting – from the viewpoint of this research – is the Work Stream 8 report on the potential contribution of the carbon markets.[26] This report estimates that during 2005-2009 the CDM produced gross revenues from CERs of €5.8bn, based on an average CER price of €14.6 per ton (the corresponding figure based on CERs issued as of July 1 2012 and using the same carbon price, would be just over €14 bn). Estimates of potential future revenues are based on the carbon price scenarios mentioned in the previous section: it is assumed that, in the low price scenario, some Annex 1 countries set up domestic cap & trade schemes to provide demand for offsets while the medium price scenario assumes that most Annex 1 countries adopt cap & trade.

Table 2.2 shows the estimated demand for offsets and resulting offset price in each scenario. The last column shows the gross revenue from primary sales of offsets – the Working Group estimated that, in the medium price scenario, gross revenues of $30bn - $50bn would translate into net revenues to developing countries of $8bn - $14bn.[27]

Table 2.2: Offset demand and price

Scenario	Offset Demand (Mt per year)	Offset Price ($/ton in 2020)	Gross Revenue ($bn per year)
Low Price	500-800	10-15	5-12
Medium Price	1,500-2,000	20-25	30-50
High Price	3,000	50	150

Source: UNFCCC

[26]http://www.un.org/wcm/content/site/climatechange/pages/financeadvisorygroup/pid/13300. (accessed July 18 2012).

[27] In the case of the CDM, it seems to be generally accepted that a relatively small proportion of the revenue from sales of offsets accrues to a project's host country. In my view elimination of this apparent market imperfection could result in significant benefits to the developing world.

2.7: THE SITUATION TODAY - FUNDING FOR ENVIRONMENTAL PROJECTS

The situation today is confusing, with many different potential or actual sources of funds for GHG mitigation or adaptation. A report for the US Congressional Research Service suggests that many donor governments believe that the existing environmental finance system has not produced satisfactory results and notes that no fewer than 15 environmental finance mechanisms were announced between 2007 and 2009 (Lattanzio, 2010). The Climate Funds Update website[28] lists 25 funding sources. The proliferation of sources complicates the task of calculating how much aid flows to developing countries in the form of climate finance: however the largest provider of funds for environmental projects generally is the Global Environment Facility (GEF),[29] set up in 1991 by the World Bank.

In 1992, the GEF was charged with providing a financial mechanism to support the objectives of the UNFCCC - it has since been given a similar role for the Convention on Biological Diversity, the Stockholm Convention on Persistent Organic Pollutants and the UN Convention to Combat Desertification. It supports the Montreal Protocol on ozone depleting substances, but does not have a formal role in that group. It is now an independently managed body, with the World Bank retaining a role as financial trustee and providing administrative backup. It provides grants and concessional finance for projects related to biodiversity, climate change, international waters, land degradation, the ozone layer, and persistent organic pollutants in developing countries and countries with economies in transition.

In addition to expenditures made on its own account, the GEF manages two special funds set up by the UNFCCC – The Least Developed Countries Fund and the Special Climate Change Fund. Both of these provide funding specifically earmarked for activities

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[28] http://www.climatefundsupdate.org/ (accessed June 29, 2012).

[29] http://www.thegef.org/gef/home (accessed April 14, 2012).

related to adaptation, and the latter (aimed primarily at countries that are heavily reliant on fossil fuels) also to technology transfer.

Funding for the GEF is provided by donor countries through a four year replenishment cycle. The amount provided reached \$3.13bn during the fourth replenishment cycle: the 5th cycle, covering the years 2010-2014 saw a sharp increase, with \$4.35bn pledged. Project expenditure during the 4th cycle was about \$725m per year (GEF; personal communication): expenditure during the 5th cycle is likely to reach about \$1.1bn per year of which roughly half is likely to be related to climate change. In almost all cases, GEF expenditure on a project is supplemented by co-financing provided by official development assistance, the government of the recipient country or the private sector through foreign direct investment. Through 2009, co-financing amounted to more than four times the amount provided directly by the GEF.

The multilateral development banks (MDBs) have been an increasingly significant source of climate mitigation funding in recent years, both through their own initiatives and through their participation in the GEF and its subsidiary funds. Expenditure by MDBs in 2009 on climate mitigation projects amounted to \$17bn (investment and lending). Projected expenditure in 2012 was expected to reach \$20.8 bn.[30]

2.8: Conclusions – the future of carbon finance

This chapter is essentially descriptive rather than analytical: as such, it does not reach conclusions. It does, however, suggest some comments on the system that has evolved through global climate negotiations and about the future development of that system. Chapters 3 through 5 of this research follow through on these comments.

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30 See http://www.un.org/wcm/content/site/climatechange/pages/financeadvisorygroup/pid/13300 (accessed July 1, 2012). The projection was published in 2010.

Firstly, it is necessary to consider whether the process of global negotiations has failed. The Kyoto Protocol was hailed as a success but it failed to involve the key global player – the US – and the participation – or lack of it - by Canada and Australia has further frustrated the objectives of Kyoto. Copenhagen was unquestionably a failure and other "successful" global agreements (Bali; Durban) are at best agreements to agree. The current situation is that the parties have agreed to agree by 2015 on a program to be implemented by 2020. Taken as a whole, Kyoto should be seen as partially successful and global negotiations since Kyoto as inconclusive.

Secondly, the CDM EB has been able to improve the CDM scheme through a series of rule changes; similarly, the EU has (belatedly) recognized the importance of adjusting rules to better match supply and demand in the EU ETS. However, neither scheme has been able to adapt to changes in the global economic situation that are the underlying cause of the recent collapse of the European carbon price. The EU actions are an important step forward for two reasons: they signify recognition on the part of the EU that a scheme such as the EU ETS cannot be managed as a purely static entity; also, recognition that the EU, as by far the largest buyer of carbon offsets, can and probably should take control of the international offsets market.

In fact, it is instructive to see the system that has evolved as a market: the product (offset credits) is produced by developers regulated by the EB; the market (the EU ETS) is regulated by the EU. The system has failed because the two sets of regulators could not coordinate their actions. It is too late to agree on coordination because the system is splintering as markets (emission trading schemes) proliferate and as some market operators attempt to achieve vertical integration through bilateral agreements that create competing regulation schemes on the production side. This deintegration of the credits market could be reversed by an all-encompassing global agreement, but, as noted above, this may be unachievable. Deintegration is not necessarily a bad thing, however, so long as the various sets of regulators can achieve some degree of coordination to ensure a reasonable global balance of supply and demand for offsets; they must recognize, also, that they are dealing with a dynamic system that must be continuously managed if balance is to be maintained.

3: Lessons from the CDM and Proposed Solutions

The successes and failures of the CDM provide lessons for the design of future offsets schemes. A key measure of its success is the sheer scale of the funds steered in the direction of developing countries: as of June 31 2012, total investment in CDM projects had reached $204bn and CERs issued (assuming an average price of $15 per CER) were worth $14.4bn.[31] Looking beyond the numbers, the successes and failures of the CDM have been analyzed in many research studies: often the conclusions reached have been severely critical. In this chapter I review a selection of published research on the performance of the CDM and some of the proposals that have been made to improve it.

3.1: The CDM: its structure and rules

The CDM is described in some detail in section 2.3.1. In summary, it has three objectives: to assist non-Annex B countries in achieving sustainable development; to "contribute to the ultimate objective of the convention" (which I interpret as simply to cut GHG emissions); and to cut the costs of emissions reductions in Annex B countries. The Kyoto Protocol itself said remarkably little about how the CDM was to operate. The details were negotiated over the four years between its signature in 1997 and COP7, held at Marrakech in late 2001, when the CDM formally came into operation.

The methodologies used to evaluate CDM projects are a work in progress: project analysis and validation proceed even while the rules are under debate. The first comprehensive CDM rulebook (see http://www.cdmrulebook.org/home) was issued only in March 2008 by Baker and McKenzie, the international law firm, with the support of the World Bank, the Asian Development Bank and various UN bodies and national

[31] My source for data on the scale of the CDM is the project database maintained by UNEP Risoe (http://www.cdmpipeline.org/).

governments. In my view, the scheme's multiple objectives and ad-hoc rulemaking process add considerably to its problems.

3.1.1: Baselines and Additionality

The issue of CERs to a CDM project raises the permitted level of emissions in annex 1 countries. This is the root of the CDM's most important problem: if it fails to promote sustainable development or to cut the cost of emissions reductions, an opportunity is missed; but if CERs are issued in respect of emissions reductions that would have occurred even without the subsidy provided by the CDM, global emissions increase and real damage is done (Fischer, 2005). To avoid this problem, a project must be "additional" – this means that "anthropogenic GHG emissions by sources are reduced below those that would have occurred in the absence of the registered CDM project activity".[32] The level of emissions that would have occurred in the absence of the project activity is known as the baseline. Additionality "has probably been the most contentious point in the development of the CDM and also resulted in great confusion amongst project developers" (Wara and Victor, 2008).

CDM rules permit four generic approaches to the determination of additionality:

- **Barrier analysis**: a project is additional if barriers exist that would prevent its development without registration as a CDM project, and these barriers do not affect at least one alternative to the project.
- **Investment analysis**: a project is additional if it fails to meet a standard profitability benchmark or if it is financially less attractive than at least one alternative project.
- **Common practice**: a project is unlikely to be additional if projects of a similar nature are already common practice in the country or sector concerned.

[32] Paragraph 43 of decision 3/CMP.1 (CMP1 refers to a conference held at Montreal in 2005).

- **Positive lists**: some categories of project are automatically deemed additional. Currently this applies only to industrial gas projects.

Barrier analysis and investment analysis are equally valid - either may be used (or both), but in practice many large projects use financial analysis while small projects generally try to prove the existence of barriers. Common practice analysis on its own does not amount to proof of additionality – it is used in conjunction with financial analysis or the barrier method as a credibility check (Schneider, 2007).

3.1.2: The project evaluation process

The CDM's requirement for case by case assessment of projects requires a complex multi-stage project evaluation process. A CDM project proposed for registration is assessed by a specialized consultant (the Designated Operational Entity, or DOE); a project design document (PDD) is posted on the UNFCCC website and the project must be approved by the CDM Executive Board (EB) and the Designated National Authorities (DNAs) of the host country and the country of the buyer of CERs. Before any CERs are issued a second DOE must certify the quantity. The complexity of this process has led to criticisms of the EB: either for subjecting projects to over-stringent assessments, leading to serious delays in project approval; or sometimes for taking insufficient time over the assessment process, enabling sub-standard projects to achieve registration.

3.2: CRITICISM OF THE CDM

The CDM "has been criticized for doing little to combat global warming; for being economically inefficient in requiring nations to cut emissions too quickly; for utilizing absolute emission caps rather than emissions intensity targets or a carbon tax; and for not committing the largest developing nations, most notably China and India, to binding emissions reductions" (Wara, 2008). And those are just criticisms of its overall design: practically every detail of its operation has been criticized individually.

Much early criticism is based on research done before the scheme was fully operational. With small samples of projects to work with, most early work was theoretical in nature (Wara, 2008). Some of the problems identified have not materialized and some that did have been eliminated by changes in rules. However more recent research has highlighted major issues that cannot easily be resolved.

3.2.1: Problems with additionality

The fundamental problem with additionality is that its determination requires a comparison of real world emissions with a hypothetical baseline – the level of emissions that would have occurred in a world in which the project did not exist (Schneider, 2007). Once additionality is established, the baseline determines the number of CERs to be issued. Recent research has uncovered many cases of project developers manipulating baselines, either to show that a project is additional when it is not, or to increase the quantity of CERs issued, thus maximizing revenues from their sale (Wara, 2008).

Schneider (2007) reviewed prior research and analyzed 93 projects. The majority of these used **barrier analysis**: in Schneider's view, the barriers cited are often not credible; some are highly subjective; some could apply to almost any project ("exchange rate risk", or "risk of a tariff decrease"); some are specific to the developer – for example, a developer with poor credit might face barriers raising finance; some ignore rules on supporting evidence – for example, 43% of projects that used barrier analysis give no evidence for the existence of barriers (Schneider, 2007).

Problems with **investment analysis** include use of a benchmark rate of return based on the expectations of the developer – realistic or otherwise (the rule requires that it reflect "standard returns in the market, considering the specific risk of the project type"

(Schneider, 2007)). Important items may be omitted – Schneider quotes Axel Michaelowa that tax benefits for wind plants in India are systematically ignored[33].

Schneider found that **Common practice analysis** suffers from the lack of any definition of common practice. Some project sponsors define prevailing practice very broadly and the technology under consideration very narrowly. In my own research I found that many small hydro projects in China achieve CDM registration: yet, according to (LBNL, 2008), 44,000 such projects existed in that country by 1997.

By definition, a project is not additional if it would have been implemented without the revenue created by the sale of CERs. By extension, if CER revenue makes very little difference to the project return, or the return including those revenues is still below the stated benchmark, it seems unlikely that the project is additional. Several researchers have analyzed the effect of CER revenues on project returns:

- Sutter and Parreño (2007) analyzed 16 projects: CER revenue had little impact of on project returns for eleven of them – these were judged unlikely to being additional. (Sutter and Parreno, 2007).
- Schneider (2007)'s analysis of 93 projects is described above: he concluded that additionality is at least questionable for about 40% of all CDM projects – this applies to all renewable energy projects other than biomass, all fuel switch projects (coal to natural gas etc) and all energy efficiency projects (Schneider, 2007).
- A study by Hoi Wen Au Yong looked at the increase in a project's internal rate of return (IRR) due to CER revenue – referred to for convenience as ΔIRR. A summary of his results for 222 projects is shown below (table 3.1). Au Yong suggested that projects with a ΔIRR below 2% should be deemed non-additional as they would

[33] Reference in Schneider is to "Experiences in evaluation of PDDs: validation and verification reports – presentation at an Austrian JI/CDM workshop, Vienna, Austria, January 26 2007". I am unable to find the document.

probably have been built without CDM registration. 26% of his projects fell into this category (Au Yong, 2009).

- Alexeew et al (2010) looked at 40 projects in India and found a strong correlation between ΔIRR and project type. They found that for almost all wind and hydro projects the IRR (without CER revenues) of was greater than 10% and ΔIRR was less than 5 percentage points (Alexeew et al., 2010).

Table 3.1: Increase in project IRR due to CER revenue

CDM Project Type	Median ΔIRR (%)
Landfill gas	19.4
Biogas	17.2
Biomass Energy	5.5
Fossil fuel switch	3.8
Hydro	2.2
Wind	2.2

Source: (Au Yong, 2009)

There are several problems with general statements about additionality. In some cases it is difficult to link cited statements to specific research findings – an example is David Victor's statement that between one third and two thirds of CERs are issued to non-additional projects (Victor, 2011). The use of small samples of projects in early studies is mentioned above: the results may still be widely cited years later - a case in point is (Michaelova and Purohit, 2007). A common problem arises when results are distorted by the choice of project types in the sample – this is particularly true of samples containing industrial gas projects, which typically receive very large numbers of CERs and have a negative IRR in the absence of CER revenue. Sutter and Parreño found that over 70% of CERs were issued to projects for which registration has a high impact on IRR, but pointed out that this result owed a great deal to the inclusion of two industrial gas projects in the sample. In my view much criticism of the CDM amounts to criticism of industrial gas projects. I provide further analysis of this issue in section 3.2.4.

The combination of a positive project IRR in the absence of CER revenues and a low ΔIRR may be a sign of non-additionality: it is certainly characteristic of project types with high construction cost and significant non-CER revenues such as renewable energy projects, (which receive revenue in the form of tariffs for electricity generated) (Alexeew et al., 2010; Au Yong, 2009; Schneider, 2007). A particular weakness of the ΔIRR approach is that it depends on the assumed value of CERs. Of the studies quoted, Alexeew et al (2010) used an arbitrary price of €10: the others gave no indication of what CER prices were used (see discussion of CER prices in section 2.4).

Despite there being room for doubt about some of the quantitative analysis, the papers referenced above cannot be ignored. David Victor's view that one third to two thirds of CDM projects are non-additional (Victor, 2011) may be based on his general experience, but that is probably a reliable guide. A Delphi survey made by Germany's Oeko-Institut found that 86% of the experts consulted believed that carbon revenues are not a decisive factor in the investment decision for CDM projects; 71% believed that many projects would be implemented in the absence of the CDM (Cames et al., 2007).[34]

3.2.2: Additionality and the role of host governments

Most national governments play key roles in the energy sector. They set energy policy, determine tariffs, enforce regulations and often own the assets employed in the industry, directly or indirectly. Almost no developing country takes a pure laissez-faire approach to energy policy: even when assets are privately owned, government "guidance" to the owners carries considerable weight. The impact on additionality arises in two ways: firstly, many investments are made in response to government

34 http://www.umweltdaten.de/publikationen/fpdf-l/3294.pdf (accessed July 20 2012).

policy decisions, regardless of profitability: these projects are not additional as they would be made without CDM financing; secondly, profitability – and thus additionality as determined using financial analysis – depends on the tariff received for electricity generated (Gang He and Morse R, 2010). Researchers have pointed to several examples of government policy effectively determining additionality: for example, the Chinese government has a policy objective to increase the use of gas in power generation yet Wara (2008) found that, as of the end of 2007, essentially all of the gas-fired generation projects then under construction in China had applied for registration as CDM activities, presumably on the grounds that they would not have been built in the absence of the CDM (Wara, 2008). Government policy may favor gas fired plants because they pollute less. Grid operators value the operational flexibility they provide - in a market system this can be recognized and valued through additional payments for plants that provide system regulation. I doubt whether such payments exist in China.

Similar issues are raised by coal-fired power stations based on supercritical or ultrasupercritical technology. A steam turbine operates more efficiently at a higher steam temperature, burning less coal and emitting less CO_2 at the same power output. The cost and complexity of the plant increases, taxing the resources of less developed countries and increasing costs, but a government taking a long term view of energy strategy might want to switch to the new technology anyway. This is the case in India, but India has successfully registered high efficiency power plants as CDM projects.

The basic problem here is that, as Wara points out, the investment analysis approach to determining additionality treats all power projects as if they were being built by independent power producers operating in a competitive, deregulated market (Wara, 2008). It is hard to think of any developing country where this would be true: certainly it is not true in either China or India. In a similar vein, He and Morse concluded that the benchmark based financial analysis methodology is incompatible with the actual market and regulatory structure in China (Gang He and Morse R, 2010).

3.2.3: The Chinese wind controversy and the E+/E- rule

The ability of governments to set electricity tariffs creates a paradox: the CDM is intended to reward investment in low emission technologies; but if a government sets a generous feed-in tariff to encourage investment in renewable generation, investors may lose access to CER revenues because the higher tariff makes the project economically viable and therefore not additional (Vasa and Neuhoff, 2011).

To eliminate this problem, the UNFCCC created the so-called E+/E- rule, which states that the effect of a national policy intended to reduce GHG emissions (an E- policy) *can* be ignored in determining additionality if the policy was implemented after the Marrakesh conference (November 11, 2001)[35]; the effect of a national policy that favors a carbon-intensive technology (an E+ policy) *must* be ignored if the policy was introduced after the adoption of the Kyoto Protocol (December 11, 1997).

Interpretation of this rule has proved difficult. A notorious example is the EB's rejection in late 2009 of ten Chinese wind generation projects as the tariffs used in determining additionality were lower than tariffs for earlier projects in the same provinces. It seemed possible that the Chinese regulator had cut tariffs to ensure that the projects were eligible for the CDM subsidy and to reduce the subsidy provided by the Chinese government.[36] In response to Chinese complaints of arbitrary treatment, the EB provided guidance[37] to the effect that, if an E- policy has been changed after November 11 2001, the additionality calculation must reflect the policy as it stood on that date.

Independent researchers agreed that the ruling was not consistent with E+/E- (Vasa and Neuhoff, 2011). The cost of a new technology typically falls with accumulated

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[35] See annex 3 to the report on EB22 (the 22nd meeting of the EB): "Clarifications on the consideration of national and/or sectoral policies and circumstances in baseline scenarios".

[36] He and Morse (2010) quote the former Head of the EB to this effect.

[37] Annex 3 to the EB54 meeting report.

experience – the reduction for a doubling of installed capacity is called the learning rate. For US wind plants the learning rate was 14.4% between 1982 and 2004 (Wiser and Bolinger, 2011). A reduction of this magnitude would certainly justify a cut in a feed-in tariff. He and Morse note that there is "no real way to know what is business as usual and what constitutes gaming of the CDM" (Gang He and Morse R, 2010). The EB seems to have decided that the Chinese government was gaming the CDM and made policy on the fly to prevent this happening.

3.2.4: Industrial gas projects

About 45% of all CERs issued as of April 1, 2012 related to projects that cut emissions of HFC-23[38] - a gaseous by-product of the manufacture of HCFC-22, which is a widely used refrigerant. As HCFC-22 is an ozone depleting substance (ODS) its use is controlled under the Montreal Protocol – see box on next page. HFC-23 has a global warming potential of 11,700, meaning that during the first 100 years after emission, one ton of HFC-23 has the same effect on climate as 11,700 tons of CO_2.[39] CDM projects that eliminate HFC-23 emissions are highly profitable: they receive 11,700 CERs for each ton of HFC-23 destroyed while their operating costs are low - they are variously estimated as less than \$0.2 per ton of CO_2e (IPCC/TEAP, 2005) and \$0.5 (Schneider et al., 2005). Total costs per ton of HFC-23 destroyed are \$2,340 - \$5,850 while revenue amounts to \$234,000 (at a CER price of \$20 per ton).

Many researchers have expressed concern that this high profitability creates perverse incentives - plant owners can earn more from CER revenues than from sales of HCFC-22. An early concern was that new plants might be built just to reap CER revenues (Schneider et al., 2005) - as a countermeasure, the EB limited CDM registration to HCFC-

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[38] Another 22% of CERs were awarded to projects that destroy N_2O - another industrial by-product gas.

[39] http://unfccc.int/ghg_data/items/3825.php (accessed June 12 2012).

22 plants that had operated for at least three years prior to the end of 2004. To prevent other forms of manipulation it set a 3% cap on the baseline ratio of HFC-23 to HCFC-22 produced: as of 2008, the average ratio at the nineteen CDM registered HFC-23 plants was 2.99% (Wara, 2008).

Commercially used refrigerants – a primer

- **CFCs** (chlorinated fluorocarbons): are potent destroyers of atmospheric ozone. Their use has been discontinued under the Montreal Protocol (with a minor exception for essential uses). In the short term they have been replaced mainly by:
- **HCFCs** (hydrochlorofluorocarbons), which have less impact on the ozone layer and are seen as a transitional stage under the Montreal Protocol. Eventually these will be replaced by:
- **HFCs** (hydrofluorocarbons). These have a low impact on the ozone layer.

Both HCFCs and HFCs have high global warming potentials. Accidental leakage and the release of refrigerant when units are scrapped result in significant quantities of these potent GHGs entering the atmosphere. Research is ongoing to identify new refrigerants that combine low impact on the ozone layer, a low global warming potential and other required properties.

The 2007 amendments to the Montreal Protocol provide that developed countries must eliminate the use of HCFCs as refrigerants by 2020 except for a very small allowance for servicing existing equipment; developing countries must freeze their output in 2013 at a baseline level equal to average 2009-2010 production then cut it to 2.5% of baseline by 2030: all use of HCFCs as refrigerants must cease by 2030 in developed countries and 2040 in the developing world.[40]

[40] http://www.epa.gov/Ozone/downloads/HCFCDecision.pdf (accessed June 12 2012).

Further rule changes have been proposed,[41] however the controversy has lost some of its relevance with the decision by the EU to ban CERs issued to these projects from the EU ETS with effect from 2013. As this is the only significant market for CERs, these credits will lose most of their value.

Is this a good thing? The UNFCCC and the EU, with the best intentions, have shut down the only global program aimed at cutting emissions of a powerful greenhouse gas at a time when these emissions are growing fast. Economic growth in developing countries raises consumers' incomes and one of the first things they do is to step up their purchases of domestic air conditioning and refrigerators, many of which use HCFC-22 as a refrigerant. Developing country consumption of HCFCs grew by about 20% per year during 1989-2007, with HCFC-22 accounting for 66.5% of all HCFCs (Velders et al., 2009). Developing countries are increasing output of HCFC-22 to meet demand, not because of some perverse incentive created by the CDM – and they have no incentive to limit emissions of HFC-23. The CDM EB's decision not to register new HCFC-22 plants means that the CDM ignores almost two thirds of HFC-23 emissions with their massive global warming potential (Montzka et al., 2010).

Industrial gas projects, in a sense, are a triumph of the offsets concept: the average cost of emissions cuts has been reduced by focusing attention on the lowest cost method. However, academic analysts tend not to see things that way: they dislike industrial gas projects as they do not promote sustainable development and because the high level of subsidy provided by CER revenues is not a cost-effective way to cut emissions – Wara described this subsidy as a "massive waste of developed-world resources" (Wara, 2008). In some cases, researchers seem obsessed with "offset quality" – this is intended to

[41] http://cdm.unfccc.int/Panels/meth/meeting/10/044/mp44_an02.pdf and http://cdm.unfccc.int/Panels/meth/meeting/11/049/mp49_an13.pdf (both accessed July 20 2012).

mean the extent to which a project contributes to sustainable development (see below) but it has become a code for inclusion or otherwise of industrial gas projects.

3.2.5: Does the CDM promote sustainable development?

One of the objectives of the CDM is the promotion of sustainable development in host countries – which raises the questions of what exactly sustainable development is, and how a project's contribution to it can be evaluated. The rules of the CDM make the host country responsible for this assessment. It is apparent that many countries show no qualms about accepting projects – such as industrial gas projects - that are cheap to implement and quickly generate CERs for conversion into hard currency, even if they bring essentially no benefit other than the CER revenue (Sutter and Parreno, 2007).

Some categories of project produce significant co-benefits that contribute to sustainable development. For example, many renewable generation technologies emit no SO_2 and NOx during normal operation. Where the baseline technology – the most likely to be used to meet an increase in electricity demand - is a coal fired generation plant, the co-benefits of a renewable generation project are likely to include improvements in human health and improved agricultural productivity due to reduction in acid rain (Partridge and Gamkhar, 2012a). In regions that experience frequent water shortages – Northern China, for example – the fact that a renewable generation project typically consumes no water during operation clearly enhances sustainability.

The co-benefits identified above create economic value compared to the baseline, but it can be difficult to estimate that value. In the special case of reductions in mortality due to cuts in air pollution linked to investment in renewable generation, (Partridge and Gamkhar, 2012a) provides estimates for Chinese projects by adapting a methodology that has been used to estimate the benefits of the Clean Air Act in the US (see (EPA, 2011)). The benefits turn out, in this case, to be less than the additional cost of electricity, but they exist and can be quantified.

Many projects create sustainability benefits that cannot be easily quantified. Karen Olsen reviewed 19 studies and commented that many attempts to "measure" sustainability amount to ticking boxes (Olsen, 2007). In fact, this is true of her own study with Jørgen Fenhann: the authors subjected 744 PDDs to thorough textual analysis, looking for indications of *how* each project contributed to sustainable development. A ranking of project types by number of boxes ticked assigns the highest score to methane reduction projects (coal bed methane, agriculture, landfill gas, fugitive methane and cement), with an average of 3.4 benefits per project. Renewable energy projects score 3.2 benefits per project while energy efficiency projects are considerably lower – surprisingly – with an average score of 2.0 (Olsen and Fenhann, 2008).

The more sophisticated multi-criteria approach seems to provide little additional insight and is heavy on data requirements (Olsen and Fenhann, 2008). Sutter and Parreño's much-cited study uses multi-attribute utility theory (MAUT) to assess the sustainability benefits of 16 projects (Sutter and Parreno, 2007). In principle, MAUT uses a utility function for each measure of sustainability, rather than simply ticking a box. In practice, the "utility function" amounts to a subjective weighting of the boxes.

Several researchers identify tradeoffs between GHG mitigation and sustainable development. Sutter and Parreño found evidence of such a tradeoff by plotting their indicator of sustainable development against the probability that a project is additional as determined by estimating the increase in the project's internal rate of return (ΔIRR) due to revenues from the sale of CERs (Sutter and Parreno, 2007). In my view, this finding depends on the extreme position on their plot occupied by two categories of project, both of which were assessed as having almost no sustainability co-benefits. One of these was landfill gas, which is surprising as Olsen and Fenhann (2008) put this type of project in their highest category for sustainable development. The other was HFC-23 destruction, which arguably should not be eligible to receive offsets at all. Ignoring these types of project, the tradeoff identified appears not to be significant.

Some studies on sustainability, in my view, raise an important moral issue: for example, Boyd et al (2009) proposed a number of solutions to the problem of projects that do not promote sustainability. Most of these solutions amount to rejecting projects that steer funds to a poor country, are acceptable to that country's government and contribute to the global goal of cutting GHG emissions but, in the opinion of the researcher, do not contribute adequately to sustainable development (Boyd et al., 2009).

3.2.6: Technology transfer and technology "leapfrogging"

The important role of technology transfer in cutting GHG emissions is enshrined in Article 4.1 of the UNFCCC, and also in Article 10(c) of the Kyoto Protocol. It is a little surprising that the CDM does not have an explicit technology transfer mandate; however the transfer of clean technology to developing countries is widely seen as at least an ancillary benefit of the CDM.[42] It is seen as a crucial element of environmental "leapfrogging" – enabling developing countries to adopt modern, clean technologies and plot a development course that avoids the environmental blight that is the norm in countries that industrialized early. By moving quickly to adopt clean technologies they can avoid "technology lock-in" – the problem of becoming dependent on very long lived assets that use old and often dirty technology (Lewis, 2010; Perkins, 2003). A coal-fired power station, for example, has an expected lifetime of fifty years.

There is some disagreement over exactly what technology transfer is. Much discussion of the topic misses the key role of "soft" technology transfer. For example, in the US and Europe the differential in construction costs between a subcritical coal-fired power plant and a more efficient supercritical[43] plant of the same size is about 4% (MIT, 2007):

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[42] http://cdm.unfccc.int/Reference/Reports/TTreport/TTrep08.pdf (accessed July 20 2012).

[43] A supercritical boiler generates steam at a higher temperature and pressure than the previously standard subcritical units: this enables it to operate at a higher level of efficiency, but

in India it is 41% (see section 4.4.2 and table 4.3). The likely reason is that the subcritical technology has been thoroughly assimilated by Indian firms while the supercritical has not. Clearly, technology in the form of design drawings and the like has been transferred: still required before the cost differential approaches that found in the developed world is a lengthy program of personnel training and familiarization, adaptation of designs to local requirements and probably the construction of several plants. Perkins (2003) wrote about the need for local development of technological capabilities, broadly defined as the knowledge, skills and expertise required to manage the process of technological change and for local firms to successfully absorb plant and equipment under local conditions (Perkins, 2003).

Studies of technology transfer in actual CDM projects provide insights – see the summary below - though careful interpretation of results is required.

- Effective leapfrogging depends on government policies directed towards clear objectives including capacity development (Perkins, 2003). Host government policies must complement support from the CDM (Olsen and Fenhann, 2008). However a project that is implemented in response to incentives set up by the national government risks being adjudged not additional.

- The CDM seems to be effective in transferring technology where this amounts in practice to little more than operator training and integration into a community (Dechezlepretre et al., 2008; Forsyth, 2005). However the needs identified by (Perkins, 2003) are an order of magnitude more complex. For supercritical power plants to be absorbed by the Indian energy sector will require coordinated actions by government departments, universities and technical institutions, over a long period. It seems unlikely that the CDM can contribute much to this process.

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the high operating temperature requires the use of sophisticated materials in its construction, with associated manufacturing difficulties.

- Many leapfrogging technologies require heavy investment in R D & D (Research, Development and Demonstration) before they become viable (Perkins, 2003) - talk of technology transfer is premature. There is a question of whether governments or the private sector should pay for this research, and of the use of any resulting intellectual property. Some researchers have suggested setting up dedicated research centers in developing countries – for example Ambuj Sagar's idea of Climate Innovation Centers (Sagar, 2010).

3.2.7: Transaction costs, registration delays and the least developed countries

During the early days of the CDM, researchers were concerned about high transaction costs linked to the complexities of the registration process. However the anticipated problem has not really materialized: many early researchers used low estimates of offset prices and sometimes analyzed very small projects. For example, (Michaelowa and Jotzo, 2005) used a price of about €4 per ton.[44] As the impact of these costs must depend partly on the ratio of transaction costs to project revenues, (including CER revenues), these studies gave a misleading impression of the importance of transaction costs, which have turned out to be less of an issue than was feared.

However the issue should not be ignored. Recent commentary on the future of the CDM has identified two important problems that are related to transaction costs: the first, and possibly the more important, is the buildup of lengthy delays in the project registration process. In the early days of the CDM this process did not work well. The quality of work done by the DOEs was variable; guidance provided to them was poor; and the EB was under-resourced and able to review only a small proportion of projects (Schneider, 2007). Victor comments that the EB was initially staffed with diplomats chosen with an eye mainly for regional diversity rather than skill (Victor, 2011). The EB

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[44] This was almost certainly not a price set in a reasonably transparent market – see my analysis of CER prices in section 2.4.

was rightly criticized for its inadequate review procedures and for its acceptance – often without review – of projects that in hindsight were clearly not additional. However with better resources – human and financial – the proportion of projects called in for review increased. With more attention being given to project reviews, a new problem arose: delays to registration began to build up. The average time taken increased from 373 days to achieve registration and 316 days from registration to first issuance of CERs in 2007 to 572 days and 607 days respectively in 2009 (World Bank, 2010).

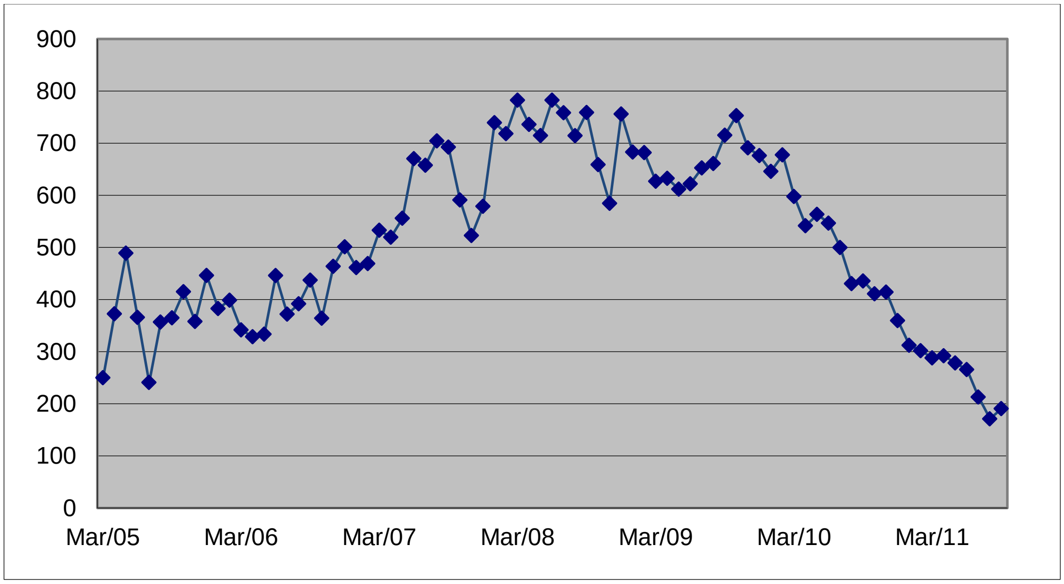
The second issue that can be linked to complexity of procedures and high transaction costs is the tiny number of CDM projects located in the least developed countries. There is a "growing perception that the distribution of credit revenues is extremely inequitable" (Wara, 2008). The problem arises partly because of the small scale of reductions that can be identified in such countries. Transaction costs that might seem trivial in the context of a typical Chinese CDM project become an insurmountable barrier for the much smaller projects that might be developed in sub-Saharan Africa.

3.2.8: Measures to simplify CDM procedures

The need to simplify CDM registration procedures as a solution to the problems noted in the preceding section has become a kind of mantra. Even Lex de Jonge – a previous Chair of the EB - writing in (World Bank, 2010), said that the CDM's stringent verification procedures would not be able to cope with the number of projects needed to make a significant difference to the level of emissions in a post-Kyoto world.

Starting in 2009, the EB responded to these criticisms by restructuring, bringing in outside experts to deal with the project backlog and simplifying its administrative procedures. Further changes, including the use of standardized baselines and emissions factors, were agreed in outline at the Durban climate conference in 2011 (see (World Bank, 2012). The streamlined procedures sound helpful and should lead to savings of time and transaction costs - however it is worth referring to chart 3.1, which shows that time to registration has fallen sharply since simple measures such as bringing in extra assessors on a contract basis were implemented, in late 2009 (the chart is taken, with permission, from an analysis by UNEP Risoe – see http://uneprisoe.org/). The EB might feel that it solved the worst of the problems that cause excessive delays three years ago.

Chart 3.1: Average time (days) from start comment until registration



Source: UNEP Risoe (http://uneprisoe.org/)

The use of default assumptions for baselines and emission factors is also potentially a sensible reform. Presumably estimates of emissions saved will become slightly less accurate – one might assume that a standardized factor is less likely to be "correct" than a custom-designed one - however the impact is likely to be small. However it is worrying that a major study made by the World Bank Carbon Finance team refers to "the standardization of baseline emissions and its embedded additionality demonstration" as "the process of establishing the baseline also determines additionality" (Platonova-Oqab et al., 2012). Setting the baseline determines whether or not emissions have been reduced: additionality depends on whether the reduction would have occurred in the absence of the subsidy provided by the CDM.

Section 3.2.1 summarizes problems with determination of additionality: the majority, and in my view the most difficult, come down to exaggeration of barriers, the use of dubious assumptions in financial analysis and (most important), the difficulty of determining whether a project would be implemented without the CDM subsidy. Standardized baselines have nothing to say about these issues. They may speed up determination of additionality, but they will make it less accurate.

Another measure aimed at simplifying registration procedures is the introduction of programs of activities (PoAs). A PoA combines large numbers of dispersed activities that cumulatively may have a large effect on CO_2 emissions but individually would not justify the cost of CDM registration – the archetypal example is the distribution of compact fluorescent lightbulbs.[45] The concept has been compared to franchising: each PoA is administered by a managing entity - typically a public sector body or an NGO. The managing entity deals with the UNFCCC and is responsible for the registration process. It does not itself carry out activities that reduce carbon emissions – its role is to provide guidance and incentives for participants to undertake CDM program activities (CPAs). The participants may be small entities such as buildings undertaking energy efficiency programs; SMEs that do not have the resources to initiate a CDM project, or farms.

PoAs have been eligible for registration since 2005, however detailed procedures were issued only in 2007. Since then, a total of 269 have applied for registration but the process has been slow: as of April 2012, 18 PoAs had been registered.[46] Registration of a PoA includes enrolment of one sample CPA: by April 2012, only 4 had actually enrolled further CPAs, and no CPA had yet had been awarded CERs.

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[45] It appears that the distribution of compact fluorescent lightbulbs would be eligible, but creation of a national standard to make their use mandatory would not be.

[46] Much of my description of PoAs is taken from a guidance document issued by the United Nations Environment Program (UNEP) – see http://cd4cdm.org/Publications/PrimerCMDPoA.pdf (accessed July 20 2012).

With no real track record to analyze it is hard to come to any categorical conclusion about PoAs, but the slow registration process and the small number that have enrolled CPAs – let alone generated CER revenue – makes it seem unlikely that PoAs are going to radically alter the fortunes of the CDM.

3.3: The future of offset mechanisms

Climate conferences since Copenhagen have pointed to the importance of new market mechanisms (NMMs) as sources of finance for GHG mitigation in the developing world. The Durban climate conference, in 2011, deferred a decision on NMMs to the 2012 conference in Qatar, but did agree on a timetable for negotiations. These will be completed by 2015, with agreed new actions against climate change to be implemented by 2020. It reiterated that these negotiations will consider the role of NMMs. Whether the intention is to replace the CDM with an NMM or supplement it is unclear; however it does seem that offset mechanisms will continue post-2020 in some form.

One approach the negotiators might take would be to retain the CDM and attempt to solve its obvious problems – summarized in section 3.2. Emma Paulsson comments that many of the papers that she examined for her review of research amounted to problem solving (Paulsson, 2009). The negotiations might also consider taking a radically different approach. In fact, there is a good reason to prefer radical change to the CDM over piecemeal improvement - this is that a re-launched CDM might be far smaller than today's version. In my view, the research summarized in section 3.2 demonstrates that the most intractable problem of the CDM is its high proportion of non-additional projects. Victor (2009) believes that insistence on strict additionality would eliminate many projects, raise transaction costs even higher and sharply reduce the role of the CDM in carbon finance. It could no longer be the principal mechanism for engaging developing countries and would lose its relevance to the task of cutting GHG emissions sufficiently to slow the rate of climate change (Victor, 2009). It is hard to argue with this view: if one eliminated from the CDM as it currently exists all industrial gas projects (on the grounds that they should be dealt with using a command and control approach) and all projects that appear to have been built in response to government policy decisions (as they are, by definition, not additional), there would not be much left.

A compromise between fixing the CDM and a genuinely radical alternative would be to move away from the project by project analysis and crediting of the CDM by adopting sectoral crediting. The EU, for example, has indicated that it wants to negotiate one or more sectoral schemes with developing countries. Another likely area for discussion will be the possibility of creating a link between issuance of offsets and the financial support that has been promised for NAMAs (nationally appropriate mitigation actions – see section 3.3.3). Finally, the discussions will probably try to create a regulatory framework for the bilateral negotiation of NMMs such as the proposed Japanese BOCM. In this section I examine the pros and cons of all of these then conclude with some discussion of a truly radical alternative.

3.3.1: Sectoral Agreements and Sectoral Crediting Mechanisms

Sectoral Agreements (SAs) have been discussed as a possible alternative to project based offset schemes for many years. The original concept called for agreement at the level of an industry sector: targets might include emissions intensity – emissions per ton of cement produced, for example – or introduction of an efficient technology – percent of kilns using heat recovery technology – or even just absolute emissions levels. Lewis distinguishes between a scheme aimed at firms working in a sector and a scheme aimed at influencing government policy (Lewis, 2010). A policy-based scheme would take the form of a government level agreement between a developed country or countries[47] and a host country, which would commit to adopt a specified climate-friendly policy. Offset credits could be awarded to the host country government corresponding to emission

[47] Or state – California may include provision for SCMs in its cap & trade scheme.

reductions that could be shown to result from the policy. An obvious problem would be how to determine whether a specific policy is driving emission reductions (Lewis, 2010). Another problem would be determination of the baseline – the level of emissions that would occur in the absence of the policy. Ideally, the policy would also meet host country objectives – for example, a policy of investment in renewable energy would cut GHG emissions: it would also cut pollution and save fuel imports (Wooders, 2011). A policy-based SA could cover a whole national economy: following the failure at Copenhagen, several developing countries proposed targets for overall emissions intensity - these could become baselines for whole-economy SAs (Wooders, 2011). The objective would be to create incentives for the national government to adopt policies that push the private sector into low carbon investments while avoiding the complexity of project by project verification (de Sépibus and Tuerk, 2011).

An SA aimed at firms operating in a sector that enables a country to generate credits when the sector as a whole surpasses its targets is a Sectoral Crediting Mechanism, or SCM (Lewis, 2010). The incentive provided by an SCM is unclear: the result achieved depends on actions taken by individual firms, but success is measured at the sector level – there is a lack of obvious incentives at the level where actions have to be taken (Lewis, 2010). On the plus side, a SCM would remove the need for project by project approvals, however crediting implies a baseline and would still require assessment of additionality – albeit at the sector level - while compliance must be verified if large numbers of valuable offsets depend on it. The requirement for international MRV[48] brings the issue of sovereignty into play. Wooders (2011) warned that developing countries are suspicious of SAs – they tend to see them as imposition of emissions caps by stealth. Another potentially serious issue is that, in a sector producing a widely traded product

[48] Monitoring, Reporting and Verification.

such as steel, it would be hard to avoid discussion of tariffs on imports from countries that are not in the agreement, leading to problems with the WTO (Wooders, 2011).

Getting the baseline wrong would have worse consequences in the case of a SCM than allowing a single CDM project to get away with a dubious demonstration of additionality. The sector-wide scale of an SCM means that, while it will make a bigger impression on GHG emissions than the CDM has if it is well designed, it will generate a much greater number of dubious offsets if it is not (de Sépibus and Tuerk, 2011). Some protection against over-generosity could be built in by setting the baseline below BAU - this would have the added advantage of ensuring that the host government had to contribute to emissions cuts (de Sépibus and Tuerk, 2011). Many researchers suggest that, if emissions turn out higher than the baseline, there should be no penalty – the host country is in a "no-lose" situation (Schmidt et al., 2008).

3.3.2: Bilateral NMM proposals

The Bali road map for action against climate change raised the potential role of new market mechanisms (NMMs) as a source of finance for GHG mitigation projects in the developing world: any new agreement on coordinated global action against climate change will almost certainly include some form of NMM. However some countries or groups of countries are pushing ahead with bilateral or multilateral negotiations on offset crediting schemes. It seems likely that at least one of these groups will reach an agreement first. The most advanced of the schemes currently under discussion is the Japanese BOCM, while the EU has stated its intention to create one or more NMMs.

- **Japan** is actively negotiating bilateral offsets deals. It has committed to an ambitious 2020 target for emission reductions and is likely to use offsets to ensure compliance. It could buy credits generated by existing Kyoto mechanisms but, presumably with an eye to the longer term, is preparing an alternative approach known as BOCM, for Bilateral Offset Credit Mechanism.[49] Japan proposes to finance GHG mitigation projects in South East Asian countries and award itself offsets reflecting the emissions reductions achieved. It is currently negotiating with several potential partners: according to CDC Climat,[50] over 100 feasibility studies have been completed or are under way. Japan hopes to issue the first BOCM credits in 2013.

- **The EU** also proposes to negotiate bilateral deals with developing countries with a view to generating offsets that would be EU ETS eligible. The EU proposal is not yet well defined, however the EU's current view is that NMMs set up under bilateral agreements would most likely be sectoral schemes. Damien Meadows, Head of the International Carbon Market unit at the EU Commission, writing in (World Bank, 2011), indicated that the EU is advocating the creation of "new and more ambitious sectoral mechanisms" set up under new multilateral and bilateral agreements that should replace the CDM in the major economies of the developing world. The CDM could co-exist with these NMMs but should focus on the least developed countries.

Likely issues with bilateral NMMs include the timing of their introduction, possible problems of overlap between schemes and the extent to which the UNFCCC should be involved. There is no obvious need for any scheme to increase the global supply of offsets prior to 2020 - there is already a significant oversupply (section 5.1.5). However the Japanese BOCM is likely to issue its first offsets in the near future. Some researchers are concerned at the prospect of a proliferation of offset units with different degrees of credibility and environmental integrity (de Sépibus and Tuerk, 2011). A potential solution would require some degree of UNFCCC involvement in the content and administration of NMMs: at one extreme, evaluation and MRV could be entrusted to the

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[49] A Japanese government website (http://www.mmechanisms.org/e/initiatives/index.html) provides regular progress reports on BOCM negotiations (accessed July 20 2012).

[50] http://www.cdcclimat.com/IMG//pdf/12-01_climate_brief_11_-_japan_s_bilateral_offset_crediting_mechanism.pdf (accessed July 20 2012).

UNFCCC: at the other, a developed country could help an undeveloped one to adopt low carbon policies and award itself offset credits according to its own assessment of their success – in fact, there is no obvious reason why a market should be involved at all.

Flues et al (2010) point out that an international authority may be less susceptible to political pressure and horse-trading than a national one (quoted in (de Sépibus and Tuerk, 2011)). There is a strong case for common accounting principles and robust standards for MRV as well as coordination between schemes to avoid double counting of reductions - as a minimum, a framework agreement for bilateral and multilateral schemes should be agreed at the level of the UNFCCC (de Sépibus and Tuerk, 2011).

3.3.3: NAMAs

There is a great deal of overlap between the concept of an NMM and the concept of a NAMA, or "nationally appropriate mitigation action" – a term that apparently first cropped up in the Bali Action Plan (see section 2.5). A NAMA is an action taken unilaterally by a developing country that is intended to reduce GHG emissions. Different actions may be appropriate for different countries - the term is not well defined (World Bank, 2012). Some NAMAs could receive financing from Annex 1 countries – in some cases a proposed NAMA may be contingent on such financing. The UNFCCC proposes to establish a registry of NAMAs, with rules for monitoring and reporting of results.

With a framework in place for registering NAMAs and at least outline rules for MRV, it would be possible for an individual NAMA to develop into a sectoral crediting mechanism (World Bank, 2012). Vasa and Neuhoff point to a key difference between this approach and that taken by the CDM: if a NAMA based on a host government policy creates a favorable environment for a low carbon project, that project would probably be adjudged non-additional if submitted for CDM registration. The CDM creates a perverse incentive not to implement such policies (Vasa and Neuhoff, 2011). A NAMA-based SCM could be used to provide reinforcement in the form of international subsidies for actions that developing countries are taking in their own interests such as the PAT (Perform, Achieve and Trade) scheme for trading of energy efficiency certificates being introduced by India (Wooders, 2011). PAT is a market based scheme intended to incentivize energy efficiency measures: it would certainly contribute to cutting GHG emissions, but as the PAT scheme is being set up by the Indian government to meet its own domestic objectives, cuts resulting from it would not be seen as additional under the rules of the CDM.

3.3.4: Getting away from the global approach

A more radical approach would be to jettison the whole package of global agreements intended to lead to offset mechanisms covering all countries and all sectors of their economies. In a recent book, David Victor suggested that negotiations between small groups of countries with similar interests – or interests that complement each other – are more likely to succeed than the global approach. If they are seen to be successful and to be serving the interests of the participants, others will want to join (Victor, 2011). In the case of offset schemes, the EU operates the world's biggest cap & trade scheme and the US, in Victor's opinion, will eventually operate an even bigger one. Given a sufficiently high price for credits (not the case today), access to offset markets linked to these schemes would offer host countries the possibility of generous subsidies for GHG mitigation projects. Better still, many of these projects serve the interests of the host country by cutting pollution or saving energy imports and the subsidies on offer would bring in private sector investment, multiplying flows to host countries.

Victor's key argument for his proposal is that negotiations over a single global scheme will run into the problem that it is not obvious which set of offsets rules will work best. The CDM is the only scheme that has really been tried, and it is deeply flawed. This lack of a clearly superior solution suggests to Victor that multiple offset systems should be encouraged to compete. The Japanese BOCM should be seen as a positive step towards the diversity that Victor advocates.

A paper by Keohane and Victor explores the institutional bases underlying alternative international climate regimes (Keohane and Victor, 2010). They see such regimes lying on a continuum between comprehensive global arrangements and fragmented local deals - they use the term “regime complex” to mean an array of narrowly focused institutions and regulatory arrangements, at best loosely coordinated, but with a common aim. In their view, differences in objectives and degrees of commitment inherent in the negotiating process and reflected in proposals for international agreements mean that key actors are likely to prefer a regime complex over any feasible agreement on a global integrated approach. They suggest, also, that a regime complex is likely to be more effective in bringing GHG emissions under control.

Taking offset schemes as an example, some other researchers agree that there is a lot to be said for diversity, provided that too much variety in the design of individual schemes does not compromise their environmental integrity (de Sépibus and Tuerk, 2011). For example, developing countries would argue for the highest possible baseline: it is not difficult to imagine a country negotiating simultaneously with two potential partners to get the best baseline deal. There is an argument for the continuing involvement of the UNFCCC – an encouraging development at the Durban climate conference in 2011 was a proposal that the UNFCCC should agree on a set of outline rules that would apply to schemes negotiated outside the UNFCCC process.

Going beyond Victor’s concept of a diversity of schemes, it is worth asking whether project origination and cap & trade compliance should be completely deintegrated. The recent changes in the EU’s rules on the eligibility of projects for EU ETS compliance are a significant precedent – they rub in the point that there are very few markets for offsets and those markets are effectively buyers’ cartels. At present the only buyers of any significance are the participants in the EU ETS – and they buy what the rules of the EU ETS allow them to buy. If the EU is prepared to take on rule making responsibility – as it has, for example, by banning offsets from industrial gas schemes – rules made by the

UNFCCC hardly matter. An agreement between the EU and Japan on standards for offset origination would close the market for sub-standard projects as effectively as a UNFCCC agreement – and might be a lot easier to negotiate.

Victor's concept for future offset schemes would completely reverse the logic that drove negotiation of the CDM, which ostensibly is not intended to cut emissions. Its objectives are to bring down compliance costs for developed countries subject to mandatory emissions caps while promoting sustainable development. If it involves the developing countries in the global effort to combat climate change, that is a bonus. Victor believes that the difficult task of negotiating a framework for new offset schemes is not worth the effort unless the result makes a real dent in GHG emissions by pushing the fast developing countries towards a low carbon development path. Reducing rich world compliance costs and promoting sustainable development are merely useful bonuses.

This opens up the proverbial can of worms. The Kyoto Protocol avoids imposing any sort of obligation on developing countries and at all climate summits since Kyoto the developing world has forcefully expressed the view that it should not be subject to restrictions on emissions because its pressing need for economic development overrides the long term need for reducing emissions; also because the developed world is responsible for most of the CO_2 in the atmosphere today and should make the sacrifices needed to reduce it. These are essentially moral arguments and they have some validity. However it is impossible to ignore the fact that a developing country – China - is the world's biggest emitter of GHGs, and India is not far behind. What is required is an approach that is likely to incentivize significant reductions from BAU emissions in these countries but does not involve setting a target and cannot be misrepresented as doing so. Carefully designed offset schemes might just achieve this.

3.4: SUMMARY – LESSONS LEARNED AND PROPOSED SOLUTIONS

A future offset scheme need not be a development of the CDM (but can learn from it), nor does it have to be agreed through the UNFCCC process. There is obvious merit in the ideas outlined in the previous section: Sectoral Crediting as envisaged by the EU; NMMs negotiated independently of the UNFCCC process, such as the proposed Japanese BOCMs and the Californian proposals; and the idea of linking NAMAs to a market based scheme. Victor's ideas about the advantages of a diversity of schemes sound convincing. A lot may depend on the success of the negotiating process currently under way and intended to finish in 2015. It might succeed in agreeing on a global level successor to the CDM (though the precedents are not good – negotiations since Kyoto have produced many agreements, but no concrete results). It might fail to agree on a successor to the CDM but produce comprehensive guidelines for bilateral schemes – David Victor would presumably say that that would be even better. Possibly the only really bad outcome would be failure to agree even on guidelines.

Without prescribing the details of a new scheme – which would be beyond the scope of this research – I outline below some guiding principles for an offset scheme that could replace or complement the CDM. It could equally well become the basis of a bilateral scheme in the context of competing schemes envisaged by Victor. In Chapter 4 I analyze two case studies and draw out lessons for a sectoral offsets scheme based on renewable energy; in Chapter 5 I consider the potential supply of offsets from a scheme such as that outlined and the potential demand, bearing in mind the warning by Vasa and Neuhoff that if a future offsets scheme is big enough to make a real impression, it is not clear how the resulting flood of CERs could be absorbed by the emissions trading market (Vasa and Neuhoff, 2011).

3.4.1: Guidelines for a future offsets scheme

The guiding principles outlined below are essentially an attempt to bring together the positive features of the proposals described in section 3.3, taking account of the problems encountered with the CDM, as described in section 3.2. It is intended to be applicable to a NMM negotiated at a global level, but could also guide bilateral negotiations in the context of scheme diversity as envisaged by Victor. In the latter scenario, an agreed set of rules with minimal guidelines for evaluation and verification and allowing for coordination of competing schemes should be negotiated, either at UNFCCC level (de Sépibus and Tuerk, 2011) or in direct negotiations between administrators of competing schemes.

- The overriding objective of a future scheme must be to reduce carbon emissions in developing countries. The level of reductions targeted should be commensurate with the scale of GHG emissions in countries such as China and India. It is not practical to base an offsets scheme on this scale on project by project review. Several researchers have pointed out the implications for assessment of additionality: for example, Grubb et al called for a change in emphasis from project-by-project additionality to a broader focus on whether the scheme channels investment flows towards lower carbon choices on a large scale (Grubb et al., 2011). Lewis questioned whether a future scheme might be better structured to encourage larger scale reductions, with less inefficiencies in transaction costs, and less ambiguity over additionality (Lewis, 2010).
- Future offsets schemes should cover individual sectors or groups of closely related sectors. A major advantage of a sectoral scheme that has not been noted elsewhere is that rules for additionality can be designed round the characteristics of the sector: arguably, one of the reasons that the CDM has failed to guarantee additionality is that its rules are over-complex as they have to cover many dissimilar sectors. Sectoral crediting schemes can be targeted on sectors with high emissions and

obvious low emissions alternatives: the hypothetical scheme analyzed in Chapters 4 and 5, aimed at incentivizing the substitution of renewable generation for coal, is an example of this targeting approach.

- An offset scheme provides a subsidy that is directly proportional both to power generated and to the expected emission saving. A capital subsidy, by contrast, incentivizes investment and may result in poorly designed projects as developers receive the incentive payment regardless of project output. India discontinued accelerated depreciation for investment in wind turbines – effectively a capital subsidy - in April 2012. The Renewable Energy Minister, Dr Farooq Abdullah, stated that accelerated depreciation had incentivized companies to erect most of India's wind generation capacity to cut their tax rather than to generate power.[51] However, a capital subsidy in the form of a grant or soft loan might be appropriate in the case of a one-off project such as modifications to a transmission grid to accommodate more wind generation. A future offsets scheme might be more effective if it operated in tandem with a fund that would finance projects that are not suitable for offset financing.
- Additionality is vitally important – if additionality cannot be proved the scheme should not award offsets. The suggestion made above that an offset scheme should incentivize performance rather than aim to remove barriers to investment implies that there is no need for the barrier analysis approach to determination of additionality. Barrier analysis has, in any case, been much abused (Schneider, 2007). Rules for determining additionality should actively reward host country policies that incentivize investment in low carbon generation schemes, rather than excluding

[51] See story on Bloomberg dated April 2, 2012. It is interesting that many wind power developers welcomed the change while the Indian Wind Turbine Manufacturers Association protested vociferously (story on *Hindu Business Line* dated April 6, 2012). It is likely that accelerated depreciation will be reinstated in the next five year plan.

them as the CDM does. An approach to the assessment of additionality that is consistent with these requirements is proposed in Chapter 4.

- Subsidies provided by the scheme should be generous enough to attract investment and should be reasonably predictable. There is a strong argument for a floor price for offsets or for demand management through flexible application of emissions caps or possibly through some central purchasing agency. Another possibility would be crediting based on emissions intensity as suggested by (Paulsson, 2009).

4: Project analysis and case studies

Asia's economic tigers – a group of fast growing developing countries – have achieved impressive rates of economic growth in recent years. An unwelcome side-effect has been rapid growth in GHG emissions (IEA, 2011), increasing the risk of disastrous climate change. A series of global climate summits has failed to agree on an effective response – however, in my conclusions to Chapter 3, I suggest that an effective response does not have to be global. A focused offsets scheme based on sectoral crediting could achieve significant cuts in global GHG emissions with only a few countries participating. In this chapter I present two case studies that suggest design parameters for an offsets scheme focused on one sector – electricity generation – and one set of countries – fast developing countries that are largely dependent on coal for their energy supply.

4.1: The problem and potential solutions

IEA forecasts[52] summarized in section 1.1 indicate that, by 2020, coal used in power stations will account for 31% of all global emissions of CO_2 from fossil fuel combustion - up from 24% in 1990. The increase has occurred entirely in the developing countries. By 2020, emissions from coal fired power stations in China and India alone will account for 17% of global emissions from fossil fuel combustion (IEA, 2011). A slowdown of the key Asian economies is possible, but these countries have shown they are capable of high growth rates and they are driven to achieve them: they are poor by western standards and must accord a very high priority to economic development. Their chosen path to development involves industrial growth, which depends on growth in electricity supply. I conclude that any realistic approach to cutting global GHG emissions should focus on cutting emissions per MWh generated in these countries.

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[52] The IEA forecasts are based on three principal scenarios. Figures quoted in this chapter are for the New Policies scenario – a summary of assumptions for all three scenarios is in Chapter 1.

Potentially, this could be achieved by increased use of nuclear power or "clean coal" – efficient coal fired power stations combined with carbon capture and sequestration (CCS). However these are long term prospects, at best. Another possibility is natural gas, which emits half the CO_2 of coal per unit of electricity generated. Proven reserves of gas in these countries are limited, but both China and India are actively exploring for unconventional gas such as the shale gas that has revolutionized the US energy scene. I discuss the possibility of unconventional gas as a partial solution to Chinese and Indian emissions problems in section 4.2.1. However, even if the gas is there, development of the infrastructure that will be needed if it is to replace a significant proportion of coal for power generation will require huge amounts of capital and a lot of time. With technological solutions and shale gas development both long term prospects – if they are going to happen at all – the only realistic option for cutting emissions from power generation in the relatively short term is renewable energy.

The problem with renewable energy is that it is expensive – and coal is cheap. The real problem, then, is financial: there is a need for a scheme or schemes to channel funds to the main coal consuming countries in the developing world to incentivize the use of renewable generation by covering at least part of the added cost compared to coal. In section 3.4.1 I suggest that the incentive provided should be linked to the expected emission saving – this is the case with renewable generation as a project's impact on carbon emissions and the added cost of electricity supplies are both proportional to power generated. Also in section 3.4.1 I make the case for combining offsets with a fund able to make grants or soft loans as some projects - modifications to a transmission grid, for example – may contribute to cutting GHG emissions, but with no direct relationship between the subsidy required and the effect on emissions. An important research objective is to examine the characteristics of renewable energy projects in developing countries to determine how different types of project might best be treated in a scheme that combined offsets with grants or subsidized loans.

In this chapter I present empirical analyses of the economic characteristics of renewable generation projects in China and India. These countries were chosen as case studies because of their size combined with their dependence on coal fired generation; however the conclusions concerning the design of a financing scheme aimed at incentivizing the use of renewable energy apply in other coal-dependent countries. The two studies have been (or will be) published separately – see (Partridge and Gamkhar, 2010, 2012b) and are reproduced in Chapters 7-9 of this document.

The analysis in both case studies is based on samples of renewable generation projects drawn from the UNFCCC database of registered CDM projects. The analysis excludes renewable technologies that are not represented in that database (geothermal, ocean energy and solar thermal generation). Solar PV is an important energy resource for India, but as of April 2012 only two grid connected solar PV plants had been registered as CDM projects in India – we estimate their generation costs but the sample is too small to arrive at useful conclusions. We did not assess biomass projects because our methodology cannot be applied to these plants: many of them supply process heat to an installation such as a sugar mill; as there is no market-based alternative source of process heat, there is no basis for estimating its value so the net cost of power generated by the project cannot be determined. The same comment applies to combined heat and power plants, of which there are a few in the UNFCCC database for China. The papers comment on gas fired power stations in China (Chapter 7) and on high efficiency coal fired plants that have been registered as CDM project activities in India (Chapter 9), however in this research I do not comment on these technologies.

The methodology of the case studies is described in section 4.2 below. The studies of China and India are summarized in sections 4.3-4.4. To avoid proliferation of citations, it should be understood that these sections are summaries of papers published – or to be published – separately (Partridge, 2012a; Partridge and Gamkhar, 2010, 2012b).

4.2: SUMMARY OF METHODOLOGY

The basis of our methodology is a comparison of generation costs between a renewable technology and a baseline. In both China and India, coal is the most important energy source - it accounted for 72% of generation in China and 66% in India in 2009. On current policies it will provide half of the expected increase in generation in China during the period 2009-2020, and 56% of the increase in India (IEA, 2011). In both countries electricity demand is growing fast – all this points to the use of the marginal coal fired plant (i.e. the next to be built) as the baseline for comparison purposes as any increase in renewable generation will displace new marginal coal capacity.

We use this cost comparison as the basis for calculation of the marginal abatement cost (MAC) for cuts in CO_2 emissions achieved by substituting renewable energy for coal fired generation in the same region. We define the MAC of project p as:

$$MAC_p = \frac{C_p - C_b}{E_b - E_p} \tag{1}$$

where C_p is the generation cost per unit of electricity generated by the project and C_b is the cost per unit for the baseline plant. E_p is the volume of CO_2 emissions per unit of electricity generated by the project and E_b is the volume for the baseline plant.

This relationship is an approximation: in reality, when some types of renewable generation (wind and solar, for example) are added to an existing national system, the volume of CO_2 emitted by conventional plants is affected as their patterns of operation change to compensate for the intermittency of the renewable resource. A more accurate – but far less analytically tractable – approach to the calculation of MAC would define E_p and E_b as emissions per unit of electricity generated by the entire system with and without the project. In section 9.2.4 I examine this effect in more detail and show that use of the simplified definition as presented above is likely to have a limited impact on the accuracy of my results.

In Chapter 3, I point to the importance of additionality in the design of an offset scheme. By definition, a project is additional if it results in a reduction in GHG emissions in the country concerned and it would not be built without the subsidy. The CDM – currently by far the largest carbon offsets scheme – has been criticized because a high proportion of projects accepted for registration are not additional (section 3.2.1). One of the objectives of this research is to demonstrate the use of an alternative approach to determination of additionality intended for a sectoral crediting scheme in the power generation sector. In summary, this is that a renewable energy project is non-additional if it would be economically rational to build it without a subsidy. It is assumed that this is the case if the project's generation cost is lower than the baseline. This new approach to determination of additionality is discussed further in section 4.6.

4.2.1: Could other fuels replace coal as the baseline?

Based on the situation today, it is reasonable to assume that the baseline generation technology in both China and India is coal. It is necessary to ask whether this assumption will always be valid – what is the prospect of another technology with lower carbon emissions per MWh generated replacing coal?

Of technologies that are reasonably well developed, only three appear to have any prospect of usurping the role of coal in China and India during the next twenty years. One is nuclear; another is unconventional gas – particularly shale gas, which has dramatically changed the energy picture in the USA; the third possibility – at least in India - is that distributed generation based on solar and biomass could absorb much of the expected growth in electricity demand.

India is something of a true believer in nuclear power, but its nuclear investment program starts from a low base and construction of a nuclear power station is a slow process. The country has plans to increase nuclear generation tenfold between 2009 and 2035 but in the latter year it will still account for less than 6% of electricity production. And like other countries, India is experiencing popular resistance to its plans for nuclear - an article in *World Politics Review* suggested that this could slow the planned growth in nuclear generation.[53] The picture is similar in China, where IEA forecasts have nuclear providing 9.5% of electricity generated in 2035. However China suspended its nuclear construction program for a year after Fukushima and may now proceed more cautiously.[54] It seems unlikely that nuclear generation will seriously rival coal in either India or China in the near future.

Natural gas is more promising: a recent IEA publication *Golden Rules for a Golden Age of Gas* (IEA, 2012) explores the possibility other countries will experience the same transformed energy outlook that the US has seen in recent years due to growth of output of gas from unconventional sources. In a high production scenario that it calls the Golden Rules Case (because companies gain public acceptance of their activities by observing rules for environmental protection) the IEA forecasts rapid growth of gas production in both China and India – between 2010 and 2035 it expects these countries to increase their gas production by 390% and 120% respectively. However in both countries demand also increases - natural gas has advantages for purposes as diverse as transport fuel and cooking. Even if output increases as forecast, both countries are expected to remain large net importers of gas. The report does not include forecasts of electricity production by fuel, but it seems very unlikely that either country will see natural gas taking over from coal as the baseline for power generation. Possibly this will happen in a few regions of China: in India, the most that can be expected is more gas fired generation in polluted urban areas and more use of gas for peaking purposes and (taking advantage of its inherent flexibility) as backup to renewables.

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53 http://www.worldpoliticsreview.com/articles/10717/indias-nuclear-energy-plans-face-post-fukushima-hurdles (accessed 07/01/2012)

54 http://www.technologyandpolicy.org/2012/03/05/chinas-nuclear-energy-industry-one-year-after-fukushima/ (accessed 07/01/2012).

Distributed generation is widely regarded as the wave of the future: a cynic might add that it always will be. However it has stirred up optimism in India, where almost 300 million people have no access to the electricity grid (IEA, 2011). The Indian government puts a high priority on rural electrification and sees distributed generation as potentially contributing to this objective. The main technologies involved are relatively simple and there is more scope for individual initiative and competition than in the gas business, with its underlying natural monopoly. There are also negatives: there are some large vested interests behind extension of the grid, which would maintain the key roles of the state owned companies and the private sector concerns that have invested in power generation. The government has prioritized distributed generation for rural areas, but will have a hard time maintaining focus when the problems in the grid connected sector are so pressing and the lobbying power of its protagonists so overwhelming.

Nevertheless, it seems likely that distributed generation as a way to meet the energy needs of rural areas will grow rapidly. It will not supplant coal as the baseline power source: what it might do is to enable India to grow its economy while expanding energy supply to all sectors of the population. If distributed generation can free up the grid connected sector to put less emphasis on a frenetic growth rate[55] and more on infrastructure, meeting peak load requirements and integration of renewables, the economy will benefit. The need to maximize investment in renewables and cut the use of coal would still be a key driver of India's energy policy, leaving the analysis presented in this research still valid.

In China there is less scope for increased use of distributed generation, if only because the power distribution grid has covered practically the whole country. Successive rural electrification programs over more than 50 years have brought electricity to 98% of the population (Pan et al., 2006).

[55] A major push to improve energy efficiency could have the same effect.

Both China and India have policies in place to increase generation from fuels other than coal: but in both cases the need for increased electricity output is huge and none of the fuels considered is likely to make much of a dent in it. I conclude that coal is the appropriate baseline for this analysis.

4.2.2: Renewable energy projects – data source and samples

The case studies presented here are based on samples of projects taken from the UNFCCC database of CDM project activities (see http://cdm.unfccc.int). This unique dataset now includes more than 4,000 registered projects located in developing countries. For each of them a project design document (PDD) is posted on the UNFCCC website. Data in the PDDs have been reviewed by international consultancy firms specialized in the field and although the assessment methods used by the UNFCCC have developed over the years, there is a high degree of consistency in presentation. Researchers have made surprisingly little use of this database, although it appears to be the only source of actual data on renewables projects in the developing world that are fully validated by private, UN certified agencies, internally consistent and cover a sufficient number of projects that statistically useful samples can be obtained.

The sample of Chinese renewable energy projects covers 100% of grid-connected projects using wind or small hydro that were proposed for CDM registration prior to April 1 2009 and had achieved registration by March 1 2010. Of the 441 projects, twenty six could not be used as the PDD did not provide sufficient data,[56] leaving a usable sample of 434 – see table 4.1. The twenty six unusable projects included nineteen wind farms and seven small hydro schemes. They were mostly early projects:

[56] Of the 26 unusable projects, 4 used barrier analysis to assess additionality, so the PDD did not need to provide financial data; the others used investment analysis but the PDD provides insufficient information to permit a proper assessment. For example, four projects provided data in US Dollars but did not include an exchange rate.

they included twenty of twenty eight projects proposed for registration through November 2006 but only six out of 432 projects proposed after that date.

For Indian projects, the sample comprises 100% of wind and small hydro projects registered as of 12/31/2011. Several of these are "split" projects – i.e. two or more sub-projects share the same UNFCCC reference number. As with the China sample, a number of projects – mainly early projects - lacked data: for example, seventeen of the 60 wind projects (including split projects) that requested registration in 2005-2007 could not be used, but for 2008-2011 the figures are two out of 199. For hydro, 27 out of 41 2005-2007 projects could not be used but only three out of 46 of the 2008-2011 projects. Table 4.1 provides a summary of both the Indian and Chinese samples used.

Despite the bias towards early projects, there is no indication that the omissions create any distortion of our results. The statistical tests used are described in Chapter 8.

Table 4.1: Project samples

Number of Projects	India		China	
	Wind	Hydro	Wind	Hydro
Registered projects	249	87	136	305
Split projects included	10	0	N/A	N/A
Projects not usable	19	30	19	7
Total sample of CDM projects	240	57	117	298

Source: UNEP Risoe

4.2.3: Estimation of generation cost

Our estimates of generation cost for both baseline plants and renewable technologies are built up from the formula:

$$Generation\ Cost\ per\ MWh = operating\ cost + capital\ cost + costs\ of\ intermittency$$

The sources for our estimates are detailed in the Appendix. In summary, the largest element of **operating cost** for a coal fired plant - fuel cost - can be calculated from the energy content of the fuel used, the delivered cost of coal and the efficiency of the plant. Estimates of operating cost elements other than fuel are obtained from various sources – the most important are project PDDs (as many CDM projects use a coal fired power station as a baseline) together with (MIT, 2007; Mott McDonald, 2006). For a wind or solar plant, fuel cost is obviously zero: operating costs and plant load factor (power generated during an average year as a proportion of the maximum possible) for renewable energy projects are given in project PDDs.

Capital cost is estimated using the annual capital charge (ACC) methodology (Merrett and Sykes, 1973) to spread the construction cost of a project over its lifetime. The ACC calculation requires estimates of cost of equity and cost of debt as inputs: for India, this research relies on published values used by the regulatory authorities to set tariffs (see http://cercind.gov.in/Current_reg.html); while for China, project PDDs provide information on standard figures used by the authorities.

We adjust our estimated cost of wind generation to reflect **costs linked to the intermittent nature of wind power**. Grid operators incur costs to provide a capacity reserve for low wind periods; there are also problems with the supply of reactive power (though control systems fitted to modern wind turbines have led to improvements in this respect). Estimation of integration costs requires a complex simulation of the complete supply system: no such exercise has been attempted in either India or China. A review of fifteen European and US studies (Holttinen et al., 2009) shows that integration costs per MWh increase with the proportion of supply to the grid contributed by wind. No simple relationship is apparent, but a conservative estimate of integration costs when wind accounts for up to 5% of total supply,[57] based on the studies reviewed in Holttinen et al, would be $1.50 per MWh. We add this $1.50 to our estimated cost of wind generation for all locations.

[57] In India, wind contributed 2% of generation in 2009 and in China less than 1% (IEA, 2011).

Another consideration related to the integration of wind into the supply system is that the grid must have the flexibility to transition from wind to conventional generation when required. India's Southern regional grid is essentially isolated - this means that wind generation in the South, which has 42% of the country's wind capacity,[58] must be backed up by spare conventional capacity in the South. The North, East, West and Northeast grids (known as NEWNE) are adequately interconnected and synchronized.

Our generation cost estimates are essentially levelized costs of electricity (LCOE) – i.e. the average cost over the life of the plant discounted back to the base year. We simplify the calculations involved by assuming that most variables remain constant in real terms over the life of the plant: the main exception is the price of imported coal (in estimates of future costs for India) – our approach to forecasting international coal prices is described in section 4.4.2.

4.2.4: Cost of coal

The single largest element of the operating cost of a coal fired power plant is the cost of coal.[59] For China, we assume that coal from Shanxi province with a GCV (Gross Calorific Value – a measure of the coal's energy content) of 5,000 kcal/kg is used throughout the country. Chinese mining companies sell coal to power stations at a mix of spot-related prices (which are published) and contract prices (which are not). Our estimates draw on online sources such as http://www.interfax.cn/news/21141. For India we estimate generation cost for both domestic and imported coal. Coal India Limited (CIL) publishes domestic coal prices – see http://www.coalindia.in/Business.aspx?tab=2. For all locations we assume the quality characteristics of typical grade supplied by CIL to thermal power stations (sample taken at Dadri power station for a study of emissions

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[58] Source: Ministry of New and Renewable Energy – www.mnre.gov.in.

[59] In our estimate of generating costs in India, fuel costs (based on domestic coal prices) account for 88% of total operating and maintenance costs.

from energy activities in India).[60] For imported coal we base cost estimates on the published specifications and prices of benchmark grade Indonesian coal with GCV of 6322 kcal/kg (most Indian coal imports are from Indonesia).

An important component of the delivered cost of coal – sometimes greater than the cost at the pithead – is transport from mine to power station. In the case of domestic coal, we define supply regions for both China and India: the delivered cost of coal is assumed to vary between supply regions but not within a region. For both countries, new power plants in the principal coal mining regions are assumed to be located at the pithead – transport costs are zero. Other supply regions are defined in terms of distance by rail from the mines. For India, freight costs to each supply region are estimated based on distances and rail freight rates, which are published. For China, rail freight rates are not published – we use rates taken from a study published in 2003, adjusted using appropriate inflation rates (Meier, 2003). We estimate the delivered cost of imported coal (for India only) using a simplifying assumption that freight rates from any Indonesian port to any Indian port are the same.

Coal costs include duties and similar charges that have the nature of payments for the use of a resource (e.g. mineral royalties). Revenue or profit based taxes are not included as they are not part of the cost of energy supply to the country – they reflect only how the government chooses to allocate costs and benefits between stakeholders.

4.3: Case Study 1 - Renewable energy in China

The first of the two case studies was published as (Partridge and Gamkhar, 2010). The analysis is based on supply areas that correspond to the regional divisions of China's electricity grid, excluding the sparsely populated Tibet Autonomous Region. We assume that marginal supplies come from mines in Shanxi province, which is the source of a

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[60] http://www.osc.edu/research/archive/pcrm/emissions/partII.shtml

third of all coal transported across provincial boundaries (LBNL, 2008); new power stations in the North and Northeast are assumed to be at pithead locations with supply costs in other regions depending on distance from Shanxi. The marginal plant in China is a 2X600MW supercritical[61] coal fired unit.

Our principal results for cost of generation and MAC are shown in table 4.2. Note that:

- Coal fired power stations in China have very low generation costs, though their coal cost is close to international price levels. The main reason is the low construction cost of Chinese plants. A comparison with the IEA publication *Projected Costs of Generating Electricity: 2005 Update* (IEA, 2005) indicates that construction costs per MW of power stations in China are less than half the average level in the OECD.

- In much of China, small hydro plants have lower generation costs than coal-fired plants. Their MAC is therefore negative (though hydro costs are site-specific so the range is wide). Our proposed approach to determining additionality would suggest that most small hydro projects in China should be assessed as not additional. According to the China Energy Databook (LBNL, 2008) there were over 44,000 small hydro stations in China at the end of 1997 - clearly the Chinese authorities thought these stations were worth building even without the CDM subsidy.

- The cost of wind generated power varied erratically over the period of the study (2006-2009). In 2009 a sharp (18%) increase was associated with a fall in the average capacity factor of Chinese wind plants. We speculate that this was linked to saturation of the transmission grid in Inner Mongolia - the region with the highest concentration of wind plants. However, over the period, wind power in all regions is significantly more expensive than coal: MACs are positive and, based on our generation cost criterion, wind generation should be deemed additional. Note that our China case study assumed the same 40 year project life for all generation

[61] See section 3.2.6 for an explanation of terms.

technologies. The same approach is taken by (IEA, 2005), but is not entirely realistic: a more reasonable estimate of the life of a wind turbine would be 20-25 years. Table 4.2 shows the effect on generation cost and MAC of assuming that the life of a wind project is 20 years.

Table 4.2: Generation cost and MAC by year and project type (China)

		Number of Projects	Generation Cost (US¢/kWh) Mean	SD	MAC (US$/tCO₂e) Mean	SD
Coal	2006	N/A	2.9			
	2007	N/A	3.5			
	2008	N/A	4.2			
	2009	N/A	4.5			
Wind: project life 40 years	2006	4	6.4	1.5	40.6	19.4
	2007	41	6.7	0.9	38.0	11.1
	2008	61	7.2	1.1	37.0	11.6
	2009	11	8.5	1.1	49.5	11.6
Wind: project life 20 years	2006		7.4		51.4	
	2007		7.7		48.8	
	2008		8.2		48.8	
	2009		9.8		63.4	
Hydro	2006	8	2.5	0.8	(5.0)	10.8
	2007	56	2.5	0.7	(13.1)	9.7
	2008	212	2.8	1.0	(19.8)	12.3
	2009	23	3.6	1.4	(12.7)	15.6

Note: SD – standard deviation.

The figures shown for coal are the averages for China's six grid regions.

- In early 2006, when carbon prices on the European market peaked, the wind power MAC averaged across all regions of China was about equal to the European carbon price. A wind generation plant receiving CERs would have been a marginally economic proposition even without the feed-in tariffs offered by the Chinese government. After the sharp fall in European permit prices that occurred in mid-2006 such plants would have required a favorable feed-in tariff as well as CER revenue to break even.

4.4: Case Study 2 - Renewable energy in India

We apply the methodology used in the China case study to a sample of renewable energy projects in India. The approach adopted is more complex than that of the earlier study, for two principal reasons: firstly, our estimates of generation costs and MAC in China are based on historic data and an assumption that costs remain constant in real terms; for India we use explicit forecasts of generation cost by technology out to 2020. The second reason for the extra layer of complexity in our research on India is that Indian energy policy is in transition – for some years the marginal plant has been the 500MW subcritical unit designed by Bharat Heavy Electricals Limited (BHEL) fueled by domestic coal. However some recent plants have adopted supercritical technology and imports of coal are growing rapidly as output of domestic coal seems to have reached a plateau. We make analyses for two baselines – the BHEL 500MW subcritical plant and a modern supercritical unit. We calculate generation costs for all locations assuming that a typical grade of domestic coal will be used; for coastal locations we also consider the use of imported coal as an alternative.

4.4.1: Cost estimates for renewable generation

Renewable generation technologies are characterized by relatively high capital costs, low operating costs and zero fuel costs (at least for the technologies considered here). For the projects in our database, the annualized capital cost accounts for 75% of total generation costs (hydro) and over 80% (wind). The future development of generation costs depends partly on the extent to which capital costs fall as developers gain experience of the technologies concerned.

As our project sample covers a longer time period (from 2005 to 2011) than the sample used for the China case study, we can use regression analysis to identify time trends. A learning curve analysis of capital cost per MW for wind projects shows a 13.3% learning rate – i.e. capital cost per MW (in constant INR) decreases by 13.3% for a doubling in cumulative capacity installed.[62] The 95% confidence interval is 10.0% - 16.6% (Partridge, 2012b) – the learning rate of 14.4% during 1982-2004 found by Wiser and Bolinger for the US wind industry falls well within this confidence interval (Wiser and Bolinger, 2011). In the US case, the cost curve flattened after 2004, trended upwards until 2009 then turned down in 2011 (based on a small sample of 2011 projects). Wiser and Bolinger related this pattern to increases in plant costs linked to the general economic situation, not specifically to the wind turbine market. India seems to have escaped the impact of this overheating, possibly because it coincided with a period of rapid development of the domestic wind turbine industry at a time when it was focusing on its local market.

A similar analysis for small hydro plants shows some indications of a learning effect, but this is significant only at the 10% level and the 90% confidence interval for learning rate spans a range from 51% to -3%.

Analyses of generation costs show different pictures for the two technologies: wind generation cost exhibits a learning effect (the learning rate is 13.3%, as for construction cost); there is no significant scale effect and costs are lower in the South. For hydro, there is no significant learning effect – this is not surprising as the technology used in these plants has changed only incrementally over many decades – and some scale

[62] Based on data on cumulative capacity obtained from the Ministry of New and Renewable Energy (http://www.mnre.gov.in/) as CDM projects are only a subset of total installations.

effect. Generation costs are lower in the North. The final models for both wind and small hydro are shown in Chapter 8.

Two grid connected solar PV plants in India have been registered as CDM projects as of March 2012. Their generation costs, based on the methodology employed for the wind and hydro cost estimates given above, are INR 11.2 and INR 14.4 per kWh. With such a small sample of projects we cannot estimate a time trend, however a recent McKinsey and Co report forecasts that LCOE for large solar PV installations in India will fall to INR 5 per kWh in 2020 (figures in 2012 currency) (Aanesen et al., 2012).

4.4.2: Cost and emissions estimates for coal fired plants

We base our emissions estimates for Indian coal on a CO_2 emission factor of .0967 tons CO_2 per GJ (NCV basis) reported by (Roy et al., 2009): for imported coal we use the IPCC default emission factor of .0946 t/GJ. By implication, we are assuming that the reduction in CO_2 emissions per MWh of generation by a renewable technology is equal to the average emissions per MWh of a coal fired plant, which is not strictly true. The output of a wind (or solar) plant varies continually due to the intermittent nature of the underlying resource; when wind power is added to a system, conventional generation plants on the system must continually vary their output to ensure that supply and demand remain in balance. The thermal efficiency of a coal fired plant is reduced by operating it at less than full load, so its emissions per MWh generated are higher. We examine evidence from US studies – particularly (Kaffine D et al., 2011) – and show that the error introduced by use of the average emissions rate is relatively small (see section 9.2.4 and table 9.2).

Generation cost estimates for coal fired plants are dominated by the cost of fuel. In our cost model, the annual capital charge accounts for 19% of generation cost, operating costs other than fuel for 9% and coal for 72% (for subcritical plants burning domestic coal). Forecasting coal prices is therefore the key to forecasting generation costs.

Pithead prices for domestically mined coal in India are published: the price delivered to the power plant includes the cost of rail freight, which depends on distance. We define supply regions (see Map 1) and estimate costs based on rail distances to mines that, on the basis of an analysis of output projections, we believe can expand production over the next decade. New power plants close to these mines (all of which are located in Eastern and Central India) are assumed to be located at the pithead. Delhi and nearby industrial regions are about 900km from a supply source; 1,300km covers the West and Southeast coast plus most of India's other industrial regions. Incremental supplies to Bangalore and the South West of India must travel more than 1,700km by rail. We exclude Assam and the isolated Northeastern region from our analysis. For forecasting purposes we assume that both pithead prices and freight cost per kilometer remain constant in real terms from 2012.

Estimates of LCOE are based on forecast costs over the lifetime of a new plant - about forty years. We assume that domestic coal prices remain constant in real terms over this period, however this would not be a realistic approach to forecasting international coal prices as these are highly volatile – see chart 4.1.[63] We define two scenarios that we believe provide upper and lower bounds for import prices.

The lower price scenario is based on the fact that coal is a quintessential commodity: it is traded in a competitive market; global reserves are large and OPEC type price controls are not feasible due to the diversity of current and potential producer countries. In the long term prices should fluctuate around the long run marginal cost of new supplies, or LRMC, which may change over time (Pindyck, 1999). Mott McDonald (UK consulting engineers) based coal price forecasts for a report on the economics of supercritical

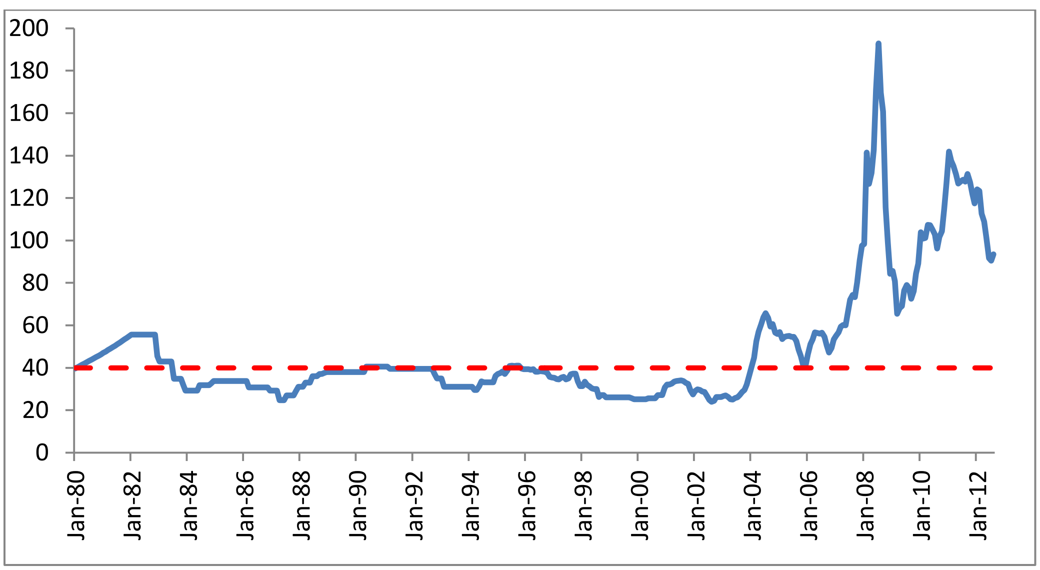
[63] The main source country for Indian coal imports is Indonesia, however chart 4.1 shows the Australian index because it has been calculated on a consistent basis for over 30 years - the Indonesian benchmark price, used in our cost estimates, has been quoted only since 2009.

plants in India on a LRMC for Pacific basin exporting countries of US$40 per ton[64] (Mott McDonald, 2006). Between 1980 and 2004 international coal prices approached this level several times then fell back (chart 4.1). This commodity type price behavior lends credibility to the Mott McDonald approach.

Since early 2004 prices have risen far above $40, driven by demand from booming Asian economies. It is likely that proposed or recently opened mines in higher cost regions such as Mongolia and more remote parts of Australia have pushed LRMC up to about $50 per ton (IEA, 2010, quoting data from Marston and IHS Global Insight). Our lower bound forecast has the Indonesian benchmark price declining to about $50 per ton (2010 Dollars) fob loading port in 2020, and then remaining constant in real terms.

Chart 4.1: Australian Coal Price Index

Price index for Australian steam coal, 6667 kcal/kg, fob Port Kembla, US$/t

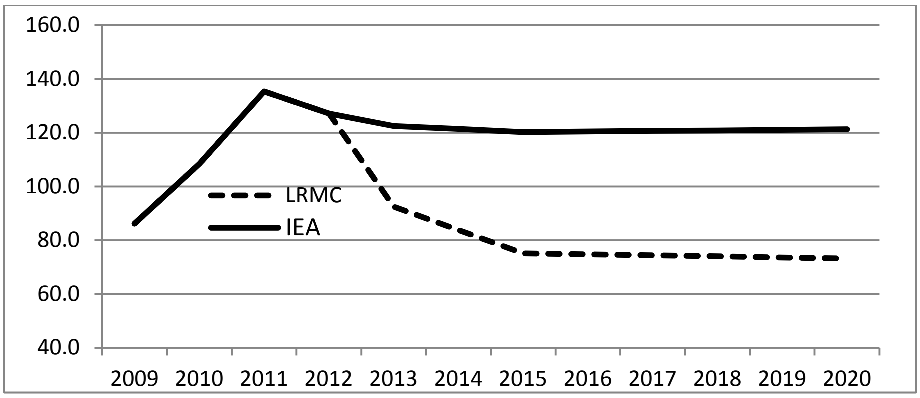


Source: IMF

[64] Metric tons are used throughout this dissertation.

For our upper bound price scenario we adapt forecasts made by the IEA for its annual World Energy Outlook. The IEA forecasts prices for a number of scenarios: we use the New Policies Scenario, which is based on energy-related policies announced (but not yet implemented) by both OECD and non-OECD countries (IEA, 2011).

Chart 4.2: Price scenarios for internationally traded coal (US$/t)



Note: prices shown are delivered price to an Indian port in US$ of 2012. To simplify the calculations we assume that freight costs to all Indian ports are the same.

The capital costs of coal fired power plants should also, in principle, fall in response to learning effects. Our estimates for the construction costs of coal-fired plants in India are shown in table 4.3: for comparison the table shows figures from an MIT report (*The Future of Coal* (MIT, 2007)), and from a report by Mott McDonald for the British High Commission in India (Mott McDonald, 2006). The three sets of figures cannot be directly compared as they relate to different countries and different years during a period when plant costs fluctuated from year to year through a boom period followed by financial crisis[65]. However we believe that the estimates are consistent for each

[65] The Mott McDonald report was published in 2006: its construction cost estimates assume all imported components erected on site using Indian labor; cost estimates in the MIT report (published in 2007) are for US projects; our construction cost data are taken mainly from descriptions (PDDs) of Indian CDM projects that applied for registration during 2008-2011.

source, so we can compare the cost differentials between subcritical and supercritical plants. We find that the cost differential between the two technologies is higher in India than in developed countries. In our view this is because the Indian subcritical plant uses Indian technology and Indian firms have lengthy experience of building plants to this design; the supercritical design is new to India and uses foreign technology. If this is the correct explanation, the high cost differential is presumably a temporary phenomenon. For forecasting purposes we assume that the capital cost of subcritical plants remain constant in real terms – the technologies involved have been in use in India for decades and further reductions due to learning are likely to be insignificant. However for supercritical plants we assume a small reduction in capital cost (15% learning rate) during 2015-2020.

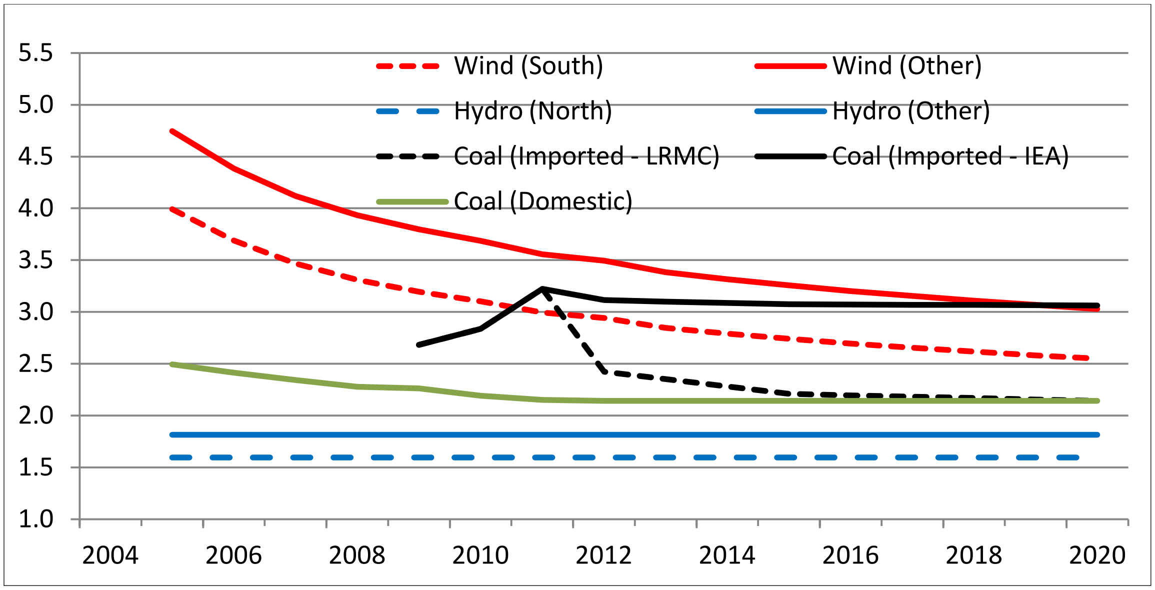
Table 4.3: Estimates of Construction Costs

US$ per kW	Subcritical	Supercritical	Difference (%)
Assumed in this research	652	920	41%
From (MIT, 2007)	1280	1330	4%
From (Mott McDonald, 2006)	1224	1293	6%

4.4.3: Generation cost comparisons

For all the technologies under discussion we estimate actual generation costs for 2009-2012 and projected costs to 2020. The results are summarized in chart 4.3 – detailed numerical results can be found in Chapter 9. In Chart 4.3, cost estimates for coal are based on subcritical technology through 2012: for later years we assume that a supercritical plant is the marginal unit. Cost estimates for domestic coal are for locations approximately 1,300km from the mine. Generation cost forecasts for wind assume a continuation of the learning effect observed over the period 2005-2011: for small hydro and domestic coal, costs are assumed to be constant in real terms from 2012. All cost estimates are stated in currency of 2012.

Chart 4.3: Generation cost comparisons - INR(2012))/kWh



Source: (Partridge, 2012a)

4.5: Conclusions – marginal abatement costs

In principle, the MAC is the carbon price at which the project would be economically viable without further subsidy. A negative MAC implies that no subsidized feed in tariff or other production-linked incentive is required: based on our proposed criterion for additionality, there should be no question of awarding offsets.

We estimate marginal abatement costs for projects in India coming on line in 2012, 2015 and 2020. The many variations of baseline plant, source of coal and supply region means that a full listing of results would be extremely complex. The most important results are summarized in tables 4.4a and 4.4b below, taken from Chapter 9. The key conclusions are that:

- MACs for small hydro are negative for all combinations of baseline plant type, coal source and price scenario - the same result as was obtained from historical data for China. In fact, hydro generation costs in the two countries are very similar. An obvious conclusion is that small hydro projects should not receive offsets.

Table 4.4a: Marginal Abatement Cost for India ($/tCO₂); plant startup 2012

LRMC Scenario		Subcritical		Supercritical	
		Domestic	Imported	Domestic	Imported
Wind:	West Coast	24.3	20.4	27.0	22.3
	Southwest	9.2	9.6	10.6	10.4
	Southeast (Tamil Nadu)	14.2	9.6	15.7	10.4
Hydro:	Delhi/North	(4.9)	N/A	(6.6)	N/A
	South & West Coasts	(5.7)	(11.7)	(6.8)	(13.3)
	Southwest	(10.8)	(11.7)	(11.9)	(13.3)
IEA Scenario					
Wind:	West Coast	24.3	5.2	27.0	7.1
	Southwest	9.2	(5.5)	10.6	(4.8)
	Southeast (Tamil Nadu)	14.2	(5.5)	15.7	(4.8)
Hydro:	Delhi/North	(4.9)	N/A	(6.6)	N/A
	South & West Coasts	(5.7)	(31.3)	(6.8)	(33.3)
	Southwest	(10.8)	(31.3)	(11.9)	(33.3)

Table 4.4b: Marginal Abatement Cost for India; plant startup 2015/ 2020

($(2012)/tCO₂)

Plant startup year & price scenario		2015		2020	
		LRMC	IEA	LRMC	IEA
Wind:	West Coast	22.4	3.4	18.8	(1.4)
	Southwest	11.2	(7.8)	8.2	(12.0)
	Southeast (Tamil Nadu)	11.2	(7.8)	8.2	(12.0)
Hydro:	Delhi/North	(6.6)	(6.6)	(6.6)	(6.6)
	South & West Coasts	(8.6)	(27.6)	(7.8)	(28.1)
	Southwest	(8.6)	(27.6)	(7.8)	(28.1)

Note: Estimates for 2015/2020 are for a supercritical unit. It is assumed to burn imported coal except in Delhi/North, where domestic coal is assumed.

- For wind generation the picture is more complex: for a baseline plant burning domestic coal (not shown in table 4.4b), MAC is always positive, reflecting the low coal price. For the same reason, MAC is always positive for plants burning imported coal in the LRMC scenario, ranging between $27.0 and $8.2 per tCO_2e.
- In the IEA scenario, for a plant burning imported coal, regional differences are important. The lower cost of wind generation in the South results in negative MACs throughout the period covered, implying that no issuance of offsets or other subsidy is required to ensure viability; however, in the rest of India, MAC is about $7/ ton in 2012, falls to about half this value in 2015 and is marginally negative in 2020.

Based on McKinsey's estimates of the generation cost for solar PV (Aanesen et al., 2012), MAC for solar in 2020 will be $42/$tCO_2e$ in the IEA scenario and $62 in the LRMC scenario – in both cases compared to a supercritical plant burning imported coal.

Our estimated MACs can be compared to carbon prices on the EU ETS, where annual average prices of EUAs have ranged between $37.85 per tCO_2e in 2008 and $10 in 2012 to date. Comparisons can be made with the IEA's projected carbon prices - in its New Policies scenario (the basis of our IEA scenario), the IEA expects a price of about 30/tCO_2e in 2020 in the EU, New Zealand and Australia, with lower prices in China and Korea (assumed to introduce carbon pricing by 2020) (IEA, 2011). The report of the UNFCCC's High Level Advisory Group on Climate Change Financing[66] makes three carbon price projections for 2020: $10-$15; $20-$25 and $50. The first two of these are consistent with the implementation (with different degrees of enthusiasm) of pledges made after the Copenhagen conference and are therefore more or less consistent with the IEA's Current Policies and New Policies scenarios. These comparisons suggest that, if international coal prices remain high, the hypothetical offsets scheme considered here would provide an adequate subsidy to ensure the viability of wind power in India.

[66] http://www.un.org/wcm/content/site/climatechange/pages/financeadvisorygroup/pid/13300

Our LRMC scenario is based on coal production economics, not macroeconomic modelling: however lower international prices in this scenario could result from a significant reduction in international coal demand, which would be consistent with a sharp slowdown in the Asian "tiger" economies. In a world where growth in these economies remained slow in the long term, the subsidy provided by issuance of offsets could be insufficient to ensure the viability of wind power in India.

4.6: CONCLUSIONS - ADDITIONALITY

Based on the proposed methodology, small hydro projects would be assessed as not additional; solar PV is clearly additional; and wind projects in India are marginally additional – their eligibility to receive offsets should be regularly reviewed. A review process is particularly important where imported coal is the marginal fuel – possibly a future offsets scheme could allow for a review of additionality every five years based on an updated set of price forecasts. As we made no analysis of cost trends for wind generation in China we cannot say whether the same conclusion would apply there, but it seems possible that it would, as Chinese coal prices are close to international prices.

The case studies demonstrate the feasibility of determining additionality based on a cost comparison between the project and the marginal new conventional plant in the country concerned. The proposed criterion is that a project cannot be additional if it generates electricity more cheaply than this baseline, as it would then be economically rational to implement the project without the subsidy provided by the issue of offsets.

The investment analysis methodology used by the CDM EB defines a project as additional if it fails to meet some standard profitability benchmark or if it is financially less attractive than at least one alternative project (see section 3.1.1). There are some similarities with the approach proposed here, but there are some key differences:

- The CDM methodology focuses on profitability, which depends on the tariff received for electricity. The tariff is typically set by a government appointed regulator. In

India, many generation schemes are built by industrial companies that intend to use the output in their other operations. In both cases – regulated tariffs and captive schemes – there is scope for obfuscation of a project's true economics.

- The CDM methodology compares projects that are not real alternatives: in both China or India there is a near-permanent need to increase electricity output; the appropriate comparison in economic terms is between renewable generation and the marginal new plant. The CDM methodologies prescribe laborious calculations of average generation costs, yet a new wind farm does not displace power from (old) coal, hydro and nuclear plants. Typically in India and China, if more electricity is supplied by wind farms, there is a reduced need for new coal fired plants.[67]
- In India – and several other countries – the marginal plant will in future be fueled by imported coal. All PDDs for Indian renewable generation schemes use domestic coal as the benchmark. The low price of domestic coal is arguably a concealed subsidy to Indian industry: its use as a benchmark requires the UNFCCC to provide countervailing subsidies to competing technologies.
- The complexity of the cost comparisons made for wind generation in the IEA scenario underline the fact that additionality is a dynamic concept. The analysis required by the CDM methodology is essentially static.

The underlying problem with the CDM's investment analysis approach (see section 3.2.1) - is that it treats all power projects as if they were set up by independent firms operating in a competitive, deregulated market (Gang He and Morse R, 2010; Wara, 2008). In reality, power markets in China and India are tightly controlled, yet the CDM methodology either assumes that they are fully competitive or requires the EB to guess

[67] A wind or solar project that supplied an isolated grid in a rural area might displace power from a diesel generator set. Note that the CDM EB is introducing standardized estimates of baseline costs and emissions, but retains the economically irrational averaging approach.

the tariff that would apply if they were. The methodology proposed here assumes that decisions are made by the government based on its rational economic objective to increase electricity supply at the least cost to the country.

5: The supply and demand for carbon offsets

A quick analysis of the likely architecture of the international offsets market after the end of the Kyoto compliance period (12/31/2012) gives the impression that little will change. The EU has confirmed that the ETS will remain a central element of its efforts to cut emissions at least until 2020, and some preparations have been made for the post-2020 period: as the EU ETS accounts for about 97% of all emissions trading today, the new schemes set up by Australia and New Zealand will not change the picture much. The WCI - the ETS set up by California and a few Canadian provinces - might, but at present it looks as if that scheme will be very self-contained, with few offsets sourced outside the USA and Canada. The CDM also will carry on, and changes recently implemented by the CDM Executive Board have dealt with at least one of its serious problems – the long delays experienced in registering a project (see section 3.2.8).

Based on the analysis described in this chapter, this appearance of continuity is misleading. The rules of the EU ETS – by far the largest market for CERs – create a hard ceiling to demand for offsets from scheme participants. In fact, recent rule changes have sharply reduced the scale of the market for CERs from most sources (section 5.1.2). Meanwhile, the CDM is creating a huge and expanding supply: the measures that have successfully cut registration delays in the CDM can only accelerate this buildup and may make the scheme's most serious problem – its failure to ensure additionality of many projects – even worse (section 3.2.8). CER prices are now so low that the CDM no longer provides an incentive for developing countries to invest in GHG reduction.

However the advantages of offset schemes as a financing mechanism justify efforts to either radically overhaul the CDM or to design a replacement. Successive climate conferences have reiterated proposals to create new market mechanisms - usually referred to as NMMs - and design work on some possible schemes is well under way (section 3.3). In Chapter 4 I examined, through "bottom up" analyses, the possible outline of a NMM operating in the electricity generation sector. In this chapter I consider the potential scale of such a scheme.

I start from an analysis of the growing oversupply of credits (CERs and ERUs) issued to projects registered under the two offset schemes created by the Kyoto Protocol – the Clean Development Mechanism (CDM) and Joint Implementation (JI).[68] For convenience I refer to both CERs and ERUs as Kyoto Credits, or KCs. This initial analysis takes the story up to 2020 - the end of phase 3 of the EU ETS and the year when the new global GHG reduction agreement anticipated in the Durban agreement is supposed to come into operation. For the post-2020 period I estimate the potential global demand for offsets and the potential supply from a hypothetical scheme that awards offset credits to projects that substitute renewable generation technologies for coal. My overall conclusion is that a sectoral scheme of this type would be feasible and would provide significant volumes of funding for GHG mitigation.

It should already be clear that this chapter will be heavy on abbreviations and acronyms. Readers should refer to the list located at the end of this document for a summary of abbreviations that relate to emissions trading schemes.

5.1: SUPPLY AND DEMAND FOR KYOTO CREDITS DURING 2008-2020

The market for offsets during the period 2008-2020 is likely to be dominated by currently existing schemes. On the demand side, phase 2 of the EU ETS lasts from 2008 to 2012, while phase 3 covers the years from 2013 to 2020. A few other schemes such as those set up by Australia and New Zealand will also be important. Forecasts of demand depend largely on analyses of the ceilings on offset usage set by the rules of these schemes. Several such analyses are available as KCs are traded securities so

[68] I should add RMUs issued in respect of carbon absorbed by forests and other sinks, but the quantities involved are too small to affect the analysis (see section 2.3).

forecasts of supply and demand in the short to medium term are of interest to the investment community. My estimates of demand for KCs during 2013-2020 draw on studies made by analysts in investment banks[69] and by the Carbon Finance team at the World Bank, which produces annual reports entitled *State and Trends of the Carbon Market* – the most recent is the 2012 edition (World Bank, 2012). Where estimates from different sources disagree I take an average; for a few datapoints – for example, offset demand in the Australian emissions scheme – I make my own calculations from economic data. My estimates are presented in section 5.1.1, for EU ETS demand, and section 5.1.3 for non-EU schemes. Table 5.1 summarizes the key elements of both.

Supply over this period will be dominated by offsets awarded to CDM and JI projects. Likely issuance is very well documented by the Danish UNEP Risoe Center,[70] which maintains records of all CDM and JI projects and KCs issued.

5.1.1: The EU schemes

The EU was embarrassed by the clear oversupply of EUAs issued in the first phase of the EU ETS (2005-2007) and took steps to ensure a tighter supply during the second phase, which ends in 2012. Supply in the first year of the period was indeed tight – actual emissions in 2008 exceeded the number of EUAs issued to scheme participants by 8.3%. However 2008 was the year that the global financial crisis took hold: EU emissions fell as economic activity waned and in the next three years the ETS saw net long positions – EUAs issued exceeded actual emissions. For 2008-2011 in aggregate - the first four years of phase 2 of the ETS – the scheme was about 1.5% long (Koeppl et al., 2012).

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[69] Key sources are Trevor Sikorski of Barclays Capital and a research team at CDC Climat. A related source is ICIS Heren – a market intelligence service.

[70] The UNEP Risoe Centre works with the UN Environment Program (UNEP) to maintain databases of CDM and JI projects and provide analysis of the schemes' performance – see http://uneprisoe.org/.

During 2008 and 2009 prices of EUAs fell sharply, then for almost two years from mid-2009 they stabilized and varied within a narrow range - it appears that ETS participants were taking advantage of the banking provisions of the scheme to build inventories of permits in anticipation of a tighter market in phase 3. The first five months of 2011 saw a 20% increase in the EUA price, in line with a general strengthening of commodity prices, but this brief spurt of optimism came to an end as the Eurozone crisis worsened. The price of December 2012 EUA futures fell by 50% over the year.[71]

The surplus of EUAs during 2008-2011 implies that the theoretical demand for KCs in the EU ETS during that period was negative. However EU ETS participants have contracted to buy large volumes of KCs –their low price provides an economic incentive to use KCs for compliance and bank surplus EUAs for use in the third phase of the scheme. Adding in the demand from Japan, New Zealand and a few other countries, the result is a rough balance of supply and demand for KCs during 2008-2012 (table 5.1).

This balance conceals the real problems in the offsets market, which appears to be approaching a crisis. The impact of weak demand due to economic factors has been exacerbated by a surge in supply. Most projects registered by the end of 2012 will be grandfathered into the third phase of the EU ETS, so developers are making huge efforts to register their projects before the deadline. Responding to pleas from developers but with truly awful timing, the CDM Executive Board has finally got its act together and speeded up the registration process. 1,103 projects were registered in 2011 – up by 37% from the 2010 total.[72] The result is a post-2012 market in massive oversupply: CER prices fell by 62% over the course of 2011 - even more dramatic than the 50% fall in EUA prices (see chart 5.1), cutting the subsidy to GHG mitigation projects in the developing

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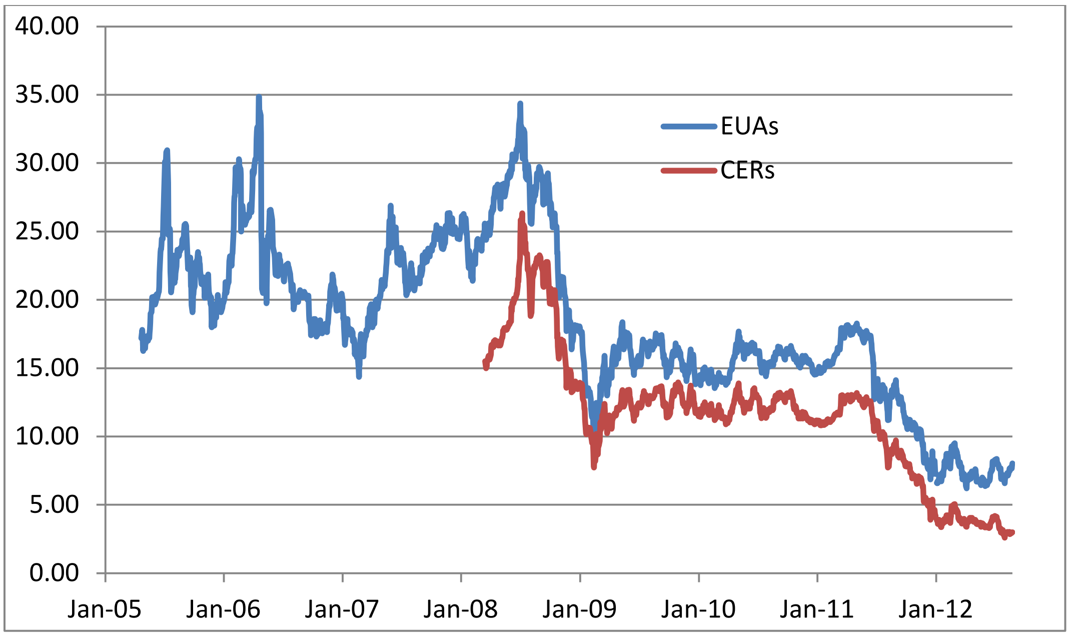
[71] In 2011 futures accounted for about 92% of secondary trading volumes in both KCs and EUAs. Unless otherwise indicated, all prices quoted for both KCs and EUAs are prices of futures with December 2012 delivery. Source is Intercontinental Exchange (ICE) Futures Europe.

[72] Source: UNEP Risoe.

world and removing much of the financial incentive to invest in new projects. The EU is considering reducing the number of EUAs to be auctioned in order to address the oversupply issue, but there is considerable opposition – for example from European steelmakers – and detailed plans have not yet been published (as of July 9 2012).

Chart 5.1: EUA and CER prices (EUR/t)



Source: ICE Futures Europe

5.1.2: EU restrictions on offset usage

The oversupply problem is compounded by changes in the EU ETS that apply from 2013. An important change, introduced by direct regulatory action (EU Regulation 550/2011) is that CERs issued to projects that incinerate industrial gases (HFCs and N_2O) will no longer be accepted for compliance purposes.[73] Other changes introduced in the most recent amendments to EU Directive 2003/87/EC include:

[73] They can be used for 2012 compliance, which means until April 2013.

- The limit on offset usage for phase 2 (including aviation in 2012) of 1,419 Mt[74] will be replaced by a limit of 1,611 Mt *for phases 2 and 3 combined*.
- KCs from any project registered before the end of 2012 will be accepted for compliance during 2013-2020 (except for projects that incinerate industrial gases). However KCs from projects registered after 12/31/2012 will only be eligible if the project is located in a country on the UN list of least developed countries and small island developing states (referred to collectively below as LDCs).
- As the Kyoto Protocol requires that an AAU must be cancelled for each ERU issued, and AAUs are valid only for the Kyoto compliance period (2008-2012), the EU is somewhat pedantically taking the view that no more ERUs may be issued after 2012.

As industrial gas projects account for 68% of CERs issued to date and LDCs for only 0.1%, these changes dramatically reduce the availability of offsets for EU ETS compliance. However it is too late to repair the damage to CER prices resulting from the oversupply of credits. A recent estimate by analysts at UNEP-Risoe is that projects already in the registration pipeline will generate 6,984 Mt of CERs during 2013-2020, of which 2,549 Mt will be ETS-eligible. However, I estimate that no more than 714 Mt of offsets will be used for compliance in the EU ETS – less than a third of the ETS-eligible supply.

The EU ETS applies to about 41% of the EU's GHG emissions. As the Kyoto commitments apply to all sectors, the EU member states have agreed to cap emissions in sectors (transport, for example) that are outside the ETS.[75] The caps apply at country level as it is not practical to monitor and control emissions from individual sources in these sectors. KCs can be used for compliance up to an annual limit equal to 3% of 2005 emissions and, to further complicate the picture (nothing is simple in the EU), twelve EU

[74] Different analysts estimate slightly different figures – there is uncertainty about, for example, the status of sub-sectors that a country has included in its cap unilaterally.

[75] See Decision No 406/2009/EC of The European Parliament.

countries may use an additional 1% of offsets but these must come from projects in LDCs. These restrictions amount to a theoretical maximum demand for KCs from EU governments of 815 Mt during 2013-2020. The source restrictions that apply to offsets in the ETS do not apply to this scheme, though some EU countries have announced that they will observe them voluntarily.

5.1.3: Offset demand beyond the EU

There are other sources of demand for KCs. The RGGI and the New Zealand scheme are already operating, however the RGGI does not accept KCs while the New Zealand scheme is relatively small. During 2013-2020 some other countries plan to introduce GHG cap & trade schemes (though in most cases, political difficulties cast some doubt over the outcome); in some cases these schemes will accept KCs and may constitute significant new sources of demand. The schemes are described in section 2.2.3 – I provide below an assessment of their likely demand for KCs during 2013-2020:

The **Regional Greenhouse Gas Initiative (RGGI)** limits power sector emissions in a number of states in the Northeastern US. It accepts offsets, with a ceiling of 3.3% of the total emissions cap. Currently only offsets generated by projects located in the RGGI states themselves can be used (see http://www.rggi.org/).

The **Western Climate Initiative (WCI)** will operate from January 2013, initially with California and Quebec as members – see http://www.westernclimateinitiative.org/. Technically each state runs its own cap & trade scheme and will accept offsets up to an annual limit of 8% of the compliance obligation. Protocols to cover eligibility of offset credits are under development: the current expectation is that offsets generated by projects in specified sectors located in the US, Canada or Mexico will be accepted. A committee is considering how to include offsets based on sectoral schemes, including REDD based forestry projects, in developing countries – the states of Acre (Brazil) and Chiapas (Mexico) have signed memoranda of understanding covering such projects

(World Bank, 2012). Plans allow for acceptance of offsets from CDM projects subject to case by case agreement – there could also be a knock on effect if WCI offset projects are set up in Mexico or other developing countries. My base case forecast assumes zero demand for KCs from WCI members during 2013-2020, with a possible upside of 20 Mt.

Both **Alberta** and **British Columbia** have GHG emission reduction targets and schemes that involve use of offsets. In both cases only offsets generated in-state are accepted.

Japan's plan to introduce cap & trade has been put on hold, but many Japanese companies participate in either the JVETS or the Keidanren scheme. Both are voluntary and both allow unlimited use of KCs. The Japanese government is also likely to be a significant buyer of offsets during the next several years. The country's efforts to cut emissions to its Kyoto target of 1,186 Mt by 2012 (6% below the 1990 level) have not been conspicuously successful - the preliminary estimate of 2010 emissions (see http://www.nies.go.jp//whatsnew/2011/20111213/20111213-e.html) was 1,256 Mt - a reduction of only 0.4% – and this was before the shutdown of Japan's nuclear capacity following the Fukushima disaster. It appears that Japan can meet its Kyoto target only by buying large numbers of KCs and AAUs.

The country faces a far more difficult task to reach the level of 946 Mt by 2020 that it committed to after the Copenhagen climate conference. The IEA forecasts that Japan's CO_2 emissions in 2020 will amount to 1,132 Mt based on current policies or 1,101 Mt assuming implementation of confirmed new policies (IEA, 2011). In the latter scenario, assuming a linear rate of reductions, the cumulative shortfall over 2013-2020 would be about 600 Mt. That is assuming that the target remains in place: recent press stories indicate that the Japanese government may revise its 2020 commitment.[76]

[76] see http://www.upi.com/Science_News/2012/06/07/Japan-to-scale-back-emissions-targets/UPI-97641339105980/.

In line with agreements at recent global climate conferences, Japan is developing a New Market Mechanism (NMM) to generate offsets from projects agreed bilaterally with other South East Asian nations. I assume in my forecasts that the government will stick to its current 2020 emissions target and that this NMM (called the BOCM, for Bilateral Offset Credit Mechanism – see section 5.2.1) will provide between 50 Mt and 300 Mt, with the remaining requirement being met by purchases of either KCs or AAUs.

Australia passed the necessary legislation to set up a cap & trade scheme in November 2011. The Australian scheme will start life in July 2012 with a fixed price on carbon (it will essentially be a carbon tax), transitioning in 2015 to cap & trade. During the fixed price phase domestic offsets will be allowed, with KCs accepted from 2015 up to a limit of 50% of the required reduction from a reference case, subject to the same restrictions on project types as the EU scheme except that RMUs will be accepted. An analysis by Barclays Capital[77] indicates that demand for KCs could be up to 430 Mt during 2015-2020, with significant downside. My own calculation gives a range of 200Mt-400Mt, which seems broadly consistent with the Barclays Capital analysis.

Until the Australian scheme commenced operating on July 1, 2012, the **New Zealand** ETS was the only national level mandatory scheme outside the EU. It is a significant purchaser of KCs as there is no quantitative restriction on their use for compliance and their current low price means that they are cheaper than New Zealand emissions units (NZUs) that are sold by the government at a fixed price. KCs are accepted subject to the same restriction on industrial gas projects as the EU ETS. Unlike the EU ETS, the New Zealand scheme accepts RMUs. The scheme is likely to use about 40 Mt of KCs during 2008-2012 (estimate by Barclays Capital). I estimate that usage during 2013-2020 will be between 60 Mt and 100 Mt.

[77] http://www.ytl-svcarbon.com/images/news/85pdf1Monthly_Carbon_Standard_-_Noise_noise_noise_noise.pdf

In Chapter 2 I describe plans by several non-Annex 1 countries (**Korea**, **Mexico** and **Brazil**) to set up emission trading schemes. None of these are likely to permit the use of KCs as offsets until at least 2020 – they will not be discussed further in this section.

Switzerland's semi-voluntary scheme (firms that choose not to participate must pay a carbon tax) is likely to be linked to the EU ETS – probably from 2014. Switzerland has purchased CERs to cover part of its Kyoto commitment under a unique agreement between the government and Swiss business organizations: a private foundation called the Climate Cent Foundation uses the proceeds of a charge on fuel imports to purchase KCs. It also operates domestic offset schemes (World Bank, 2012). Arrangements post-2012 depend on the EU ETS linkage. I assume KC usage in a range from zero up to 15Mt, which is consistent with an estimate in (World Bank, 2012).

5.1.4: Cap & Trade in China

After the Copenhagen conference China made an unconditional commitment to reduce the emissions intensity of its GDP to 40% - 45% below its 2005 level by 2020. A key element of China's plan to achieve this target will be a cap & trade scheme - the National Development and Reform Commission (NDRC) has announced that pilot schemes will be set up in five cities and two provinces – see (World Bank, 2012). Judging by comments made by Chinese officials, a national scheme will be introduced – possibly by 2015, more likely by 2020 – if the pilot schemes show that the idea is workable in Chinese circumstances. For more detail of the proposals see section 2.2.4.

In July 2012 the NDRC released outline regulations for the creation of tradable offsets.[78] Eligible projects must be either registered CDM projects that have not yet generated offsets, projects permitted by the Chinese authorities to apply for CDM registration that have not yet been registered, or projects that adopt NDRC methodologies (not specified

[78] A translation of the NDRC document is at http://thecleanrevolution.org/_assets/files/Interim-Regulation-of-Voluntary-Greenhouse-Gases-Emission-Trading-in-China(1).pdf.

in detail yet, but apparently based on the CDM rulebook). Several market analysts[79] have pointed out that the export of CERs issued to Chinese CDM projects must be approved by the NDRC and that approvals issued to existing projects will be exhausted by about the end of 2015. The same Bloomberg story quotes Pradeep Perera - an energy expert at the Asian Development Bank – as saying that China may impose restrictions on export of CERs. Perera leads the ADB team that is providing advice and funding for the pilot schemes mentioned above.

This raises a very interesting issue: China is the source of 60% of the offsets traded on the markets linked to the EU ETS. If it wants to count reductions achieved by CDM projects towards a domestic target it cannot simultaneously export those reductions in the form of CERs – this would amount to double counting. It looks very much as if China intends to subsume existing CDM projects into a domestic offset scheme to support its cap & trade plans. A researcher at DTU (the Danish Technical University) noted that the CERs from all Chinese CDM projects registered or in the validation pipeline as of late 2010 would cover about 15% of the country's GHG reduction commitment (Luetken, 2010). Luetken's suggestion that China might set up a scheme to invest in GHG mitigation projects in Africa and import credits seems to me unlikely (but if it happened it would certainly shake up the global carbon market).

5.1.5: The overall supply and demand balance 2008-2020

Table 5.1 summarizes my forecasts of supply and demand for KCs during phases 2 and 3 of the EU ETS. For 2013-2020 the forecasts are presented as a range: in general, the "minimum" demand estimates are a relatively conservative base case forecast assuming slow recovery from the current economic crisis in Europe, while the "potential" demand

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[79] http://www.bloomberg.com/news/2012-01-30/china-may-keep-emission-offsets-after-2015-adb-official-says.html

figures are the maximum permissible under EU rules or my assessment of the upper end of the likely demand range from non-EU schemes (see section 5.1.3).

Table 5.1: Supply and Demand for KCs 2008-2020 (Mt CO_2e)

	2008-2012	2013-2020	
		Minimum	Potential
Demand			
EU Governments	262	400	800
EU ETS	897	714	714
Total EU	1,159	1,114	1,514
Switzerland	15	0	15
Japan	125	50	300
New Zealand	40	60	100
Australia	0	200	400
US & Canada	0	0	20
Other Annex B	22	0	20
Total Demand	1,361	1,424	2,369
Supply			
EU ETS eligible CDM	434	2,549	2,549
Other CDM	668	4,435	7,255
JI	288	0	0
Total KC Supply	1,390	6,984	9,804
Surplus/(Deficit) - Total	29	5,560	7,255

Supply projections in table 5.1 are from the analysis by UNEP Risoe of projects in the CDM and JI pipelines (http://uneprisoe.org/). For EU ETS-eligible CERs, this analysis is likely to be accurate as a very high proportion of the projects that will generate these CERs is already in the pipeline. The JI and non-ETS-eligible forecasts may be less accurate but are less relevant to my analysis. The "potential" supply includes the UNEP

Risoe estimate of CERs issued to projects not yet in the registration pipeline. The forecasts are subject to great uncertainty, however some conclusions can be drawn:

- My forecast of EU ETS demand during 2008-2012 is 897 Mt CO_2e: analysts' estimates range from 865 Mt to 1,161 Mt. The range does not reflect major differences in approach by different analysts: given that AAUs, EUAs and KCs can all be used for EU ETS compliance, and all are in surplus; actual demand for KCs will depend largely on what European companies see as their least cost (or most convenient) choice. The EU ceiling for phase 2 offset use is 1,419 Mt.
- EU firms hedge their compliance needs by buying EUAs or KCs in advance of requirements. Sometime in phase 3 of the EU ETS (2013-2020), advance purchases will be sufficient to cover expected demand through to 2020. Analysts differ in their views on when this will happen: CDC Climat believes that it could be late 2013 – others see a later date. A survey by ICIS Heren[80] noted that market prices for ETS-eligible and non ETS-eligible CERs are essentially equal – the looming surplus of ETS-eligible KCs means that the market sees no reason to apply a price premium.
- For non-EU ETS eligible KCs the oversupply is even worse: they will be accepted by the ETS for 2012 compliance (until April 2013); after that a market exists until mid-2015, which is the final date for nations that ratified the Kyoto Protocol to establish compliance. In reality, most countries already own all the offsets they will need.

It seems likely that, in the fairly near term, KC prices will fall almost to zero. It is not clear how this prospect can be reconciled with the projected carbon price in 2020 of $30/t in the IEA's World Energy Outlook (see section 4.5) unless the IEA anticipates large scale purchases of KCs to meet compliance requirements in new cap and trade schemes.

[80] http://www.icis.com/heren/articles/2012/01/17/9524688/emissions/edcm/analysis-when-will-the-eu-ets-cap-on-kyoto-offsets-be-reached.html

This final price collapse would mean that the Kyoto offset schemes would no longer be a viable source of finance for GHG mitigation projects. This would be a somewhat ignominious end for the CDM: for all its faults, it has provided significant funds for investment in much needed GHG mitigation projects in the developing world. According to estimates made by the Carbon Finance team at the World Bank, the value of CERs under contract has reached $28bn and total investment in the projects concerned will total more than $130bn if all projects are completed as planned.[81] No other scheme has even come close to those totals. As of July 1 2012, 4,296 projects have been registered and a further 4,443 are in the pipeline. Apart from its success in incentivizing low carbon investment, it seems likely that the CDM has helped the European economies by cutting the cost of GHG mitigation in countries with EU ETS obligations. Whether it achieved its objective of promoting sustainable development is debatable, but there is no doubt that all that investment in developing countries has promoted some kind of development.

5.2: OFFSETS POST-2020

The focus on new market mechanisms (NMMs) in climate change negotiations makes it likely that offset schemes have a future beyond 2020, but it is not clear what form they might take. However, the EU's liking for sectoral schemes (and their advantage – see Chapter 4 – that rules and methods of determining additionality can be tailored around specific types of project) make it likely that large scale offset schemes post-2020 will be organized on a sectoral basis. In this section I analyze the potential scale of an offsets scheme that would operate during the period 2021-2035 for projects that substitute electricity generated using renewable technologies for electricity generated from coal. I provide what have to be seen as very approximate forecasts of offset supply from

[81] Estimates are from (World Bank, 2012). The valuation of CERs sold includes those sold forward under term contracts and not yet delivered. The total investment figure assumes a 5:1 ratio of CER value to overall investment, based on World Bank experience.

projects of this type and of the potential demand for offsets from developed countries. My forecasts are based on projections of emissions reductions and electricity generated by type of technology taken from the long term energy sector projections in the IEA's annual *World Energy Outlook* – the most recent version was published in November 2011 (IEA, 2011). I show that an offsets scheme of the type envisaged is feasible and that it could be designed and managed to match offset supply to likely demand.

5.2.1: New Market Mechanisms

The Bali road map for action against climate change mentioned the potential importance of new market mechanisms (NMMs) as a source of finance for GHG mitigation projects in the developing world. Any new agreement on coordinated international action against climate change is likely to include some form of global NMM, however some groups of countries are pushing ahead with their own proposals for bilateral or multilateral agreements on offset crediting schemes. It seems likely that at least one of these groups will reach an agreement first. Bilateral NMMs could potentially significantly alter the supply and demand for offsets during the period I am considering. The most advanced of the schemes currently under discussion is the Japanese BOCM, while the EU has stated its intention to create one or more NMMs.

- **Japan's** shortfall against its 2020 target for emission reductions is 155 Mt: this could become a cumulative shortfall for 2013-2020 of about 600 Mt (section 5.1.3). It could fill the gap by purchasing non ETS-eligible CERS, which are cheap. However, with an eye to the longer term, Japan is preparing an alternative known as the BOCM, for Bilateral Offset Credit Mechanism.[82] Japan proposes to finance GHG mitigation projects in South East Asian countries and award itself offsets for the emissions cuts achieved. It is currently negotiating a number of bilateral deals -

[82] A Japanese government website (http://www.mmechanisms.org/e/initiatives/index.html) provides regular progress reports on BOCM negotiations.

according to CDC Climat,[83] over 100 feasibility studies have been completed or are under way - and hopes to issue the first BOCM credits in 2013. My forecasts assume that BOCM credits will cover half of Japan's cumulative shortfall during 2013-2020 (they also assume that Japan will not simply eliminate that shortfall by changing its emissions target – see section 5.1.3).

- **The EU** also proposes to negotiate bilateral deals with developing countries with a view to generating EU ETS eligible offsets that would not be subject to the restrictions that apply to the use of KCs during 2013-2020. The EU proposal is not yet well defined, however the EU's current view is that NMMs set up under bilateral agreements would most likely be sectoral schemes (as described in section 3.3.1).

While the Japanese BOCM is likely to issue its first offsets in the near future, the current huge oversupply of KCs means that there is no need for an increase in the global supply of offsets prior to 2020. In the following section I discuss the prospects for a hypothetical NMM that would operate from 2020. I assume that the KC surplus that will exist in that year can be reduced or eliminated by demand management measures or will be soaked up by new cap & trade schemes operating post 2020.

5.2.2: Offset supply post-2020

The most likely scenario for offset supply post-2020 seems to include coexisting NMMs, each covering only one sector or possibly a group of sectors with similar characteristics. In this scenario the CDM would survive (if it survives) in a much reduced form focused on project types and host countries not covered by any NMM - possibly LDCs. This outcome is more or less what David Victor expects (Victor, 2009). In this section I

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83 http://www.cdcclimat.com/IMG//pdf/12-01_climate_brief_11_-_japan_s_bilateral_offset_crediting_mechanism.pdf

estimate the potential supply of offsets from a hypothetical global NMM aimed at incentivizing investments in electricity generation using renewable technologies.

I have not attempted to design a scheme in any detail, though my review of criticisms of the CDM in Chapter 3 at least provides a checklist of problems to be avoided. I assume that my hypothetical scheme would award offsets in proportion to the emissions saved relative to the marginal new generation plant in the country concerned. The two case studies presented in Chapter 4 examine CDM projects in China and India - two key countries where the marginal plant is coal-fired. I believe that the lessons of these two cases can be applied in other coal-dependent countries (South Africa and Indonesia, for example) but not necessarily elsewhere. However, for simplicity, I estimate the potential supply of offsets as if the scheme applied to all non-Annex 1 countries.

I calculate the scheme's potential for offset creation on the basis of the IEA's forecasts of electricity generation in the New Policies scenario, taken from the current *World Energy Outlook* (IEA, 2011). The scheme is assumed to apply to increases in generation from 2012: i.e. all renewable generation plants in operation during 2012 are covered by the CDM; all new plants by the new scheme. To illustrate the methodology used I provide below (table 5.2) an example of the IEA's electricity generation forecasts. Referring to table 5.2, a brief description of the method used to estimate potential offset creation for (say) wind in India is:

- I estimate generation for each technology in 2012 by interpolation and calculate the increase in wind generation from 2012 for each year after 2012.
- I assume that any increase in wind-generated electricity displaces the same quantity of generation using coal - the marginal generation technology. Using an estimate of CO_2 emissions per kWh for a coal fired plant (see India case study in section 4.4.2 for how this is derived) I calculate emissions avoided by the increase in wind generation.
- The potential offset creation due to wind generation is the amount of CO_2 avoided.

Table 5.2: Electricity generation by technology – India (TWh)

	1990	2009	2015	2020	2025	2030	2035
Coal	192	617	898	1,080	1,231	1,431	1,716
Oil	10	26	24	19	14	13	12
Gas	10	111	148	243	319	418	536
Nuclear	6	19	44	65	110	145	184
Hydro	72	107	147	208	290	338	352
Biomass & Waste	-	2	7	19	47	83	122
Wind	-	18	41	63	98	139	183
Geothermal	-	-	-	-	1	1	2
Solar PV	-	-	9	23	49	94	140
CSP	-	-	1	2	5	9	15
Marine	-	-	-	-	-	-	1
Total Generation	289	899	1,319	1,723	2,162	2,671	3,264

Source: (IEA, 2011)

This calculation provides an estimate of the maximum potential for offset creation – there is no intention to present the results of the calculations as a practical offset scheme. Applying this methodology to the IEA's estimates of generation through 2035 for all non-Annex B countries, I arrive at the figures shown in table 5.3 below.

Table 5.3: Forecast supply of credits from renewable energy projects (million tons CO_2e)

Project type	2013-2015	2016-2020	2021-2035
Biomass	131	542	5,633
Hydro	791	2,742	17,949
Solar	31	234	3,885
Wind	486	1,422	9,752
Other Renewables	21	79	797
Total	1,460	5,019	38,016

5.2.3: Offset demand and the supply/demand balance 2020-2035

The IEA forecasts of CO_2 emissions for various regions can be used to obtain some idea of the potential demand for offsets after 2020. A subset of these forecasts is shown below (table 5.4).

Table 5.4: CO_2 emissions by Annex 1 countries (Mt)

	1990	2009	2015	2020	2025	2030	2035
EU 27	4,035	3,529	3,542	3,377	3,186	2,981	2,827
OECD NAM	5,578	6,152	6,418	6,233	6,050	5,865	5,650
Total Annex 1	15,180	15,032	15,685	15,397	15,039	14,678	14,288

Source: (IEA, 2011)

To gain an idea of the scale of potential demand for offsets during 2020-2035 I rely on analogies with the EU schemes – both the ETS and the more recent targets allocated to EU governments for emission reductions in non-ETS sectors. So far these EU schemes are the world's only large scale user of carbon offsets – they provide at least some indication of how a wider scale scheme might operate. I implicitly assume that all Annex 1 countries will accept GHG emissions caps after 2020 - a highly dubious assumption, but it provides an upper bound estimate. I proceed as follows:

- Total Annex 1 emissions in 2020 are 15,397 Mt. The EU ETS applies to 41% of total EU emissions – I adopt this same percentage for the Annex 1 countries. Total 2020 emissions for the whole of Annex 1 would be 6,315 Mt in an emissions trading scheme and 9,082 Mt outside the scheme.
- Assuming that the target for total ETS emissions in 2035 is also 41% of total Annex 1 emissions in that year, and assuming a straight line profile of emission reductions over the period, aggregate ETS emissions over 2021-2035 would be 91,081 Mt.

- During phase 2 of the EU ETS the ceiling on use of offsets is 13.6% of total permitted emissions from ETS sectors over the period. Applying this ceiling to the Annex 1 countries in 2021-2035, the offsets ceiling is 12,390 Mt.
- For non-ETS sectors, the EU permits total annual offsets usage of 3% of 2005 emissions in assessing compliance with its reductions targets. Applying this percentage to 2020 non-ETS emissions for the whole of Annex 1, over fifteen years, the ceiling on offsets usage in non-ETS sectors would be 4,087 Mt for 2021-2035.
- For ETS and non-ETS sectors in combination in all Annex 1 countries, the potential demand for offsets during 2021-2035 would be 12,390 + 4,087 = 16,477 Mt, or 1,098 Mt per year.

As already noted, I see this figure as an upper bound estimate. It can be compared to forecasts made by the offsets sub-group of the High-level Advisory Group on Climate Change Financing (section 2.6). These range from global demand for offsets in 2020 of 500-800 Mt per year in a low carbon price scenario up to about 3,000 Mt assuming a high carbon price. In a medium price scenario (the assumed carbon price is $20-$25 per tCO_2e, which is broadly compatible with my own figures), the forecast range of offset demand is 1,500Mt – 2,000 Mt - this is somewhat higher than my own forecasts, but not disproportionately so. The most likely reason for the difference is that the sub-group assumed a higher ratio of offsets used to emission reductions actually achieved.

5.3: MANAGING OFFSET SUPPLY

The demand estimate presented in the preceding section is less than half of my estimate of potential supply of 38,016 Mt from an offset scheme confined to the renewable energy sector (table 5.3), with significant additional volumes likely to be generated by offset schemes in other sectors. Even adopting unreasonably optimistic assumptions about new cap & trade schemes that might operate after 2020, the potential supply of offsets would swamp demand, resulting in price collapse and the loss of any incentive for investment in renewable energy – a repeat of the situation we are seeing today. In this section I consider how the rules of a renewable energy NMM could be drawn to bring supply more in line with demand. It turns out that there are a number of ways to achieve this, and most of them would improve the environmental and economic integrity of the scheme.

Firstly, in section 5.1.4 I described China's tentative plan to introduce a national cap and trade scheme by 2015 in order to reduce the country's GHG emissions. This plan is clearly welcome in itself – one suspects that the Chinese leadership is concerned that the country is being cast as a climate change villain as well as being worried by the vulnerability of some parts of the country to changed climate and – particularly – to rising sea levels. Several analysts have suggested that China might voluntarily withdraw from the CDM in 2015 or 2020.[84] As China is the largest single source of CERs, removing Chinese projects from a proposed renewable energy NMM would be a big step towards bringing future offsets supply and demand into balance.

In Chapter 4 I presented case studies of CDM projects based on renewable electricity generation technologies in India and China. A common feature of the two studies was that the generation cost of small hydro projects is below the cost of coal fired generation - the likely alternative in both countries. In the conclusions to Chapter 4 I suggested that hydro projects should not be awarded offsets as they are very probably not additional. There is at least anecdotal evidence of real barriers to small hydro projects – for example, in many regions lack of transmission capacity limits the number of projects that can be built. These barriers add to costs, but the costs are not related to the amount of electricity generated. Direct financial aid to break down barriers might

[84] See section 5.1.4. The possibility is also discussed in Barclays Capital: Monthly Carbon Standard dated August 25, 2011, and by (Luetken, 2010).

well be justified, but a subsidy per MWh – which is what an offset scheme provides – is not. I would suggest removing all hydro projects from the proposed NMM.[85]

The case study on India suggested that the rate at which the costs of wind generation are falling could bring them close to parity with coal fired generation (based on imported coal) within a few years. Whether or when this happens depends on the future course of prices of coal in international trade. I would suggest that any renewable energy NMM agreement should contain, from its outset, a commitment to keep wind generation costs under observation and to remove new wind projects from the NMM in any country if they reach cost parity with coal.

Finally, proposals for sectoral crediting mechanisms (SCMs) sometimes suggest that setting a ratio of offsets to GHG reductions would deal with the additionality problem. This is a somewhat dubious proposition: if a project is not additional it should receive no offsets – by awarding half the number of offsets you first thought of you presumably do half the damage to the environment, but you are still giving offsets to a non-additional project. However, an advantage of awarding offsets on a less than one for one basis is that the ratio could be adjusted to avoid providing an excessive subsidy to a project that needs only a small additional incentive to become profitable – see, for example, my comments on wind projects in India in section 4.5. It is also true that adjusting the ratio of offset credits to GHG reductions achieved could be justifiable as a means of sharing the burden of the subsidy between the host government and the international community. This reasoning could justify providing one offset for two or three tons of avoided emissions to a wind project: technologies such as solar PV, for which generation cost appears to be far higher than the coal fired alternative, should receive one credit for each ton of CO_2 eliminated.

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[85] This would also address the concerns expressed by many environmentalists about subsidies to any type of hydro project (Pottinger, 2008).

The effect on offset supply of the suggested measures is summarized in table 5.5 below.

Table 5.5: Offset supply (Mt) – alternative scenarios

	Offset Supply
Base Case Supply	38,016
Supply Management Measures	
Withdrawal of China	(18,957)
Omit Hydro (excl China)	(9,931)
Apply one for two ratio to Wind	(1,469)
Revised Supply	7,659
Potential Demand	16,477

5.4: CONCLUSIONS – OFFSET SUPPLY AND DEMAND

Table 5.5 shows the results of these possible supply management measures. It would not be appropriate to present these suggestions as even a rough outline of a possible NMM. Not only are my estimates of offset supply and demand during 2020-2035 highly uncertain but it is unlikely that all Annex 1 countries would participate in this or any other offset scheme. My estimate of offset supply can be seen only as a rough estimate of maximum possible supply from one of several sectors that might be suitable for a global NMM. However, even with these provisos, the supply/demand analysis in this section demonstrates the feasibility of designing a NMM that would incentivize investment in electricity generation using renewable technologies.

A vitally important issue in the design of any new scheme is the need for some form of offset supply/demand management. The situation today is that supply of CDM projects, and therefore of offsets, has ballooned, possibly reflecting a supply curve (relating supply of projects to carbon price) that is significantly higher than was suspected. An alternative explanation is that the oversupply reflects the number of projects accepted for registration that would be built anyway, even without the subsidy provided by the

CDM (see section 3.2.1). If a project is going to be built anyway, it is economically rational to apply for CDM registration if the expected revenue from sale of CERs exceeds the transaction costs of the registration process – an extremely low hurdle. At the same time, economic problems in Europe have cut the level of emissions to the point where the number of EUAs issued exceeds total compliance demand: the theoretical demand for CERs is zero (see section 5.1.1 and (Koeppl et al., 2012)).

In the absence of effective supply/demand management the ever-present threat of complete price collapse must eventually threaten the viability of the market, and certainly must reduce the incentive offered to project developers – or, at least, those whose investment decisions really do depend on the availability and size of the CDM subsidy. I suggest ways that this could be achieved: an obvious measure would be to disallow offsets from developing countries that choose to operate their own cap & trade schemes. Most important of these would be China, but Korea and some other countries are considering similar schemes (section 2.2.3). Other supply management measures would include disqualifying projects that are judged non-additional and awarding offsets to projects that are only marginally additional at a ratio of less than one offset per ton of CO_2e emissions saved.

The implication is that additionality – as determined by comparison of generation cost with baseline cost – should be seen as a dynamic, not a static concept. The rules of any future offsets scheme must recognize this by allowing for periodic reviews of project eligibility, with possible resets of the ratio of offsets to emissions reductions.

After all supply management measures the proposed scheme would generate 7,659 million tons of offsets over fifteen years – that is close to 0.5 bn tons per year, or roughly double what the CDM has provided per year since 1/1/2010. This is a maximum level that is unlikely to be reached. At an offset price of $20 per ton, the contribution to carbon finance globally would be just over $10bn per year, or 10% of the $100bn proposed carbon fund.

6: The Way Forward – discussion and conclusions

Climate change is a complex problem. The process of global negotiations and the system of agreements and organizations that have emerged from those negotiations are correspondingly complex. This complex system shows signs of failing: a better approach for the future might be to identify the key elements of the problem, assign priorities, and then look for simple solutions to each individual element.

In section 1 of this research I break down the emissions problem by sector and type of country: it is clear that a very high priority must be assigned to cutting emissions by the energy sector in the developing world. Breaking this emissions category down further, it becomes clear that the fastest emissions growth rates occur in a small number of rapidly growing countries in Asia that are heavily dependent on coal for power generation. During the period from 1990-2035, forecast emissions from coal fired power stations in China will increase by 740%: in India the increase is expected to be 600% (IEA, 2011). Cutting these countries' reliance on coal for power generation could have a significant impact on global GHG emissions. An analysis of possible alternatives to coal in China and India presented in section 4.2.1 indicates that technologies such as nuclear cannot provide the required growth in electricity supply in the necessary time frame.

An alternative that is available now is renewable energy. However electricity from renewable sources is expensive and its costs are front end loaded – in India in 2009, the initial investment cost per MW of wind generation was almost 70% higher than the cost of a coal fired plant (figures from generation cost model – see Chapter 4). At this point the problem becomes one of finance. A scheme that would channel funds to the developing world to incentivize the use of renewable generation by covering part of the added cost would contribute significantly to reducing global greenhouse gas emissions.

In designing an incentive scheme for this purpose there are good reasons to adopt a market based approach – specifically one based on offsets. Market based solutions have theoretical advantages (Coase, 1960; Montgomery W D, 1972): they also have the practical advantage that private sector funds channeled through offsets are probably more reliable in the long term than direct government to government flows (Victor, 2011). The agreements reached at recent climate conferences – Cancún in 2010 and Durban in 2011 – have included proposals for new market based mechanisms (NMMs).

This research presented here sets out to clarify the key parameters of an offsets scheme that would provide financial incentives for investment in renewable generation in developing countries that are reliant on coal. The research comprises a "bottom up" analysis of renewable generation projects in China and India, aimed at clarifying how they might fit into an incentives scheme; and a "top down" study of the potential scale of the scheme. The research also includes a review of criticisms that have been made of the CDM: this arrives at the conclusion that the criticism that many CDM projects are not additional is a valid one. The research proposes an improved methodology for assessment of additionality and analyses its effectiveness.

6.1: Lessons from the CDM

I review criticisms of the CDM in the existing literature and consider some proposed solutions. I conclude that:

- The overriding objective of a future offsets scheme must be to reduce carbon emissions in the fast-developing countries. The level of reductions targeted should be commensurate with the scale of emissions in these countries – this would imply a scheme significantly larger than the CDM. It is not practical to base such a large offsets scheme on project by project review, as is the case with the CDM (Grubb et al., 2011). Current efforts to improve the environmental integrity of the CDM while maintaining its basic structure can only result in turning it into a niche scheme, too small to make any significant difference to global carbon emissions (Victor, 2009).

- Many problems identified during the early years of the CDM have been dealt with through changes in the rules of the scheme; however one very serious criticism has not - many CDM projects are not additional. When an offset is issued to a non-additional project, global emissions actually increase. A key design criterion for future offset schemes must be that they should guarantee additionality.
- A future offset scheme should not follow the example of the CDM by trying to cover all project types in all sectors. Sectoral crediting mechanisms – offset schemes for projects in one sector only – have been much discussed. The EU, in particular, has championed these schemes. A sectoral scheme would avoid the need for project by project assessment but must guarantee additionality for the sector.
- David Victor has taken the radical view that, as the only large scale carbon offsets scheme (the CDM) has not worked well and there is no clear agreement on what should replace it, there are advantages in encouraging a diversity of schemes (Victor, 2011). In this context of scheme diversity, some analysts suggest that a set of rules with guidelines for project evaluation and the coordination of competing schemes should be agreed at UNFCCC level (de Sépibus and Tuerk, 2011). An alternative view is that this is unnecessary. There are very few markets for offset credits and the EU, which operates by far the largest, has already shown its willingness to impose its own rules by disallowing some types of project. Beyond about 2020 there are likely to be fewer than half a dozen significant markets for offsets. Their operators should ideally agree on common rules for eligibility – this would be easier and more effective than achieving any agreement at all at UNFCCC level.
- Not all types of project are suitable for offset financing, which seems best suited to a situation where the need for subsidy is proportional to the expected emission saving. For example, a wind farm's impact on carbon emissions and the added cost of electricity supplies are both proportional to power generated; however modifications to a transmission grid to accommodate more wind generation are

better suited to funding by means of a grant or soft loan. This suggests that a future offsets scheme would be more effective if it operated in tandem with a fund that would finance projects that are unsuitable for offset financing.

- Finally, one of the most important lessons to learn from the CDM is that an offset scheme is ineffective if the price of offsets is too low to create an incentive for investment in low carbon projects. There is a need to dynamically manage the supply of offsets to ensure that the scheme offers continuing adequate incentives.

6.2: Lessons learned from the case studies

I present case studies of renewable energy projects in China and India, based on comparisons of generation costs between the projects and a baseline. The comparison provides a basis for calculation of the marginal abatement cost (MAC) for cuts in CO_2 emissions achieved by substituting renewable energy for coal fired generation.

The case studies enable me to test a proposed methodology for the assessment of a project's additionality. I note in section 6.1 that a key criterion in the design of an offsets scheme is that it should award credits only to projects that are additional: a project is additional if it results in a reduction in GHG emissions and it would not be built without the subsidy provided by the credits.[86] I suggest that a project is not additional if it would be economically rational to build it without the subsidy. It is assumed that this is the case if the project's generation cost is lower than the baseline.

The India case study looks at Marginal Abatement Costs and additionality in the context of increasing consumption of imported coal. As the price of coal in international markets has been highly volatile in recent years, forecasts of generation cost require a

[86] This is a simplified version of the official definition that a project is additional if "anthropogenic GHG emissions by sources are reduced below those that would have occurred in the absence of the registered CDM project activity" – see section 3.1.1.

systematic approach to forecasting the future price of coal - in the case study I use a scenario based approach. Given the impossibility of making accurate forecasts of coal prices on the international market over the lifetime of a project, the agreement setting up an offset scheme for the generation sector should allow for periodic review of prices.

Based on the proposed methodology, I conclude that small hydro projects in both China and India should be assessed as not additional (they are currently the largest category of CDM project in both countries); solar PV should be assessed as additional; and wind projects in India are marginally additional – their eligibility to receive offsets should be regularly reviewed. In my view, this analysis shows that the proposed approach to assessment of additionality is feasible and offers several advantages over methodologies permitted by the CDM. It requires an appropriate choice of baseline and accurate assessment of generation costs but in the context of a sector based scheme, this analysis could be made annually rather than project by project.

Where a category of project is assessed as non-additional it would not be appropriate to award offset credits, but in some cases genuine barriers to investment might exist that would justify some other form of subsidy. I suggest that the appropriate solution to this problem lies in direct funding through grants or soft loans. I suggest in section 6.1 that a future offset scheme might be linked with a fund able to make grants of this nature.

6.3: SUPPLY AND DEMAND IN THE OFFSETS MARKET

I present two analyses of the supply of offsets and the potential demand. The first, relating to the years 2013-2020, is based on forecasts made by the World Bank Carbon Finance Team and by analysts working in investment banks. It assumes that the carbon markets during the period in question will be dominated by schemes that already exist or are firmly planned. The second – an analysis of potential supply of offsets from a sector specific scheme to operate after 2020 and of potential global offset demand – uses a new approach based on IEA forecasts for the global energy sector.

The picture that emerges for the earlier period is one of serious oversupply leading to market collapse. The EU has tried to deal with the problem by drastically restricting the eligibility for EU ETS compliance of offsets awarded to some project types, but the measures are too little, too late. Considering only EU ETS credits, projected supply during 2013-2020 significantly exceeds the upper end of the range of projected demand. The market price of offsets has fallen sharply – the most recent price (07/24/2012) is €3.15 – this compares to a peak in 2005 of over €32 per ton. At this price level, the CDM does not offer an effective incentive for investment in renewable energy projects.

My analysis of the potential scale of an offsets scheme to operate during the period 2021-2035 assumes a hypothetical scheme for projects that substitute electricity generated using renewable technologies for electricity generated from coal. I combine this with a forecast of potential demand for offsets from developed countries during the period. Both supply and demand forecasts are based on projections of emissions reductions and electricity generated by type of technology taken from the long term energy sector projections in the IEA's annual *World Energy Outlook* (IEA, 2011).

My initial conclusion is that this hypothetical scheme could also suffer from oversupply of offsets. I assess the scope for supply management measures to reduce this potential oversupply: firstly, in section 5.1.4 I describe China's tentative plan to introduce a national cap and trade scheme to reduce the country's GHG emissions. Several analysts have suggested that China might voluntarily withdraw from the CDM in 2015 or 2020.[87] As China is the largest single source of CERs, removing Chinese projects would be a big step towards bringing offsets supply and demand into balance. Similar considerations would apply to Korea and some other developing countries that are considering introducing cap & trade schemes (section 2.2.3).

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[87] The possibility is discussed in Barclays Capital (Monthly Carbon Standard dated August 25, 2011), and by (Luetken, 2010). See also http://www.bloomberg.com/news/2012-01-30/china-may-keep-emission-offsets-after-2015-adb-official-says.html.

In Chapter 4 I present case studies of CDM projects based on renewable electricity generation technologies in India and China. A common feature of the two studies is that the generation cost of small hydro projects is below the cost of coal fired generation: based on my proposed approach to assessment of additionality, hydro projects should not be eligible to receive offsets. I would propose removing all hydro projects from the proposed NMM.[88]

Finally, a generation technology with costs close to the costs of the marginal conventional generation technology could receive less than one offset per ton of CO_2 emissions saved. This policy would provide additional assurance that projects <u>on average</u> are additional. Based on the conclusions of my India case study (Chapter 4), it might be appropriate to restrict offsets awarded to wind generation projects in this way as wind generation costs are close to parity with coal fired generation based on imported coal. I would suggest that any renewable energy NMM agreement should contain, from its outset, a commitment to keep these costs under observation.

After taking account of realistic measures to restrict eligibility, a hypothetical scheme focused on incentivizing investment in renewable energy would contribute less than half of the estimated global demand for offsets. The gap leaves room for offset schemes in other sectors and for the probability that not all developed countries will participate in cap & trade schemes that allow international offsets. The scheme could generate 7.7 bn tons of offsets over fifteen years – about 0.5 bn tons per year, or roughly double what the CDM has provided per year since 1/1/2010 (this is a maximum level that is unlikely to be reached). At an offset price of $20 per ton, the scheme would contribute just over $10bn per year in financing for low carbon projects in the developing world.

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[88] This would also address the concerns expressed by many environmentalists about subsidies to any type of hydro project (Pottinger, 2008).

6.4: THE NEED FOR REVIEW

At several points in this summary of my conclusions I point to the need for any future offsets scheme to allow for periodic review of its operations – a feature that is completely missing from the CDM. A successful offsets scheme should be managed as a flexible and dynamic system – it is unlikely that a system of this nature could ever result from politically contentious negotiations involving 194 countries.

- To avoid oversupply, it is essential that the scheme should incorporate some form of offset supply/demand management, based on a periodic review of supply trends and of likely demand as countries set up or modify cap & trade schemes.
- Additionality, as assessed using my proposed methodology, depends on the expected future course of coal prices. Any renewable energy NMM should contain, from its outset, a commitment to keep these prices under observation and to remove a technology from the scheme if its generation cost reaches parity with coal.
- Similarly, the additionality of projects based on technologies that are close to cost parity with coal should be reviewed periodically and the ratio of offsets to emissions reductions reset.

In conclusion, I have not attempted to present in this dissertation a detailed design for a future offset scheme. However my analysis of a hypothetical scheme that would aim to incentivize the replacement of coal fired generation in developing countries with renewable energy indicates that such a scheme is feasible and it could be managed to avoid the problems of oversupply of offsets followed by price collapse that have affected the CDM. Effective supply management would ensure that the subsidies provided by the scheme would be generous enough to attract investment and reasonably predictable. Depending on the level of participation by developed countries, the scheme could operate at a sufficient scale to significantly reduce global GHG emissions.

PART 2: THE CASE STUDY PAPERS

7: The role of offsets in a post- Kyoto climate agreement: the power sector in China[89]

7.1: INTRODUCTION

The Clean Development Mechanism (CDM), created by Article 12 of the Kyoto Protocol, is a market-based mechanism intended to cut the cost of compliance with greenhouse gas (GHG) emission reductions mandated by the Protocol. Kyoto requires developed countries (the "Annex 1 countries") to cut emissions, but the CDM enables them to offset their commitments by paying for projects that cut emissions in the developing world. The rationale is that the cost of cutting emissions is believed to be lower in developing countries. A second objective of the CDM is to promote sustainable development in poorer countries; a third is to involve the developing countries in an international effort to limit GHG emissions.

To date – mid-March, 2010 - over 2,000 projects have been registered under the CDM; China – the world's biggest emitter of greenhouse gases - is the biggest user of the CDM with other key developing countries such as India not far behind; and over 385 million certified emission reductions (CERs) have been issued, meaning that projects registered under the CDM have been responsible for cutting GHG emissions by 385 million tons. In each case, the developing country concerned has confirmed that the project promoted sustainable development.

These figures seem impressive, however it has been suggested (Schneider, 2007; Wara and Victor, 2008) that some of the 385 million tons of "registered and verified" emission cuts are not real - that the CDM actually increases the level of global emissions by

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[89] By Ian Partridge and Dr Shama Gamkhar (Dr Gamkhar is co-Chair of Ian Partridge's dissertation committee). Published in Energy Policy Vol 38 Issue 8; August 2010 and reproduced here by permission of the editor. ©2010. Published by Elsevier Ltd.

allowing Annex 1 countries to avoid cutting without substituting real cuts elsewhere. Sathaye and Phadke (2006) show that projects using imported technologies to cut emissions in developing countries may cost more than cuts in Annex 1 countries, raising the cost of emissions cuts while enriching the provider of the technology.

We have not attempted to assess the validity of these criticisms as regards the totality of the CDM. Instead we focus on one key sector – grid connected electricity generation – and on three generation technologies: wind, small hydro and natural gas combined cycle (NGCC). In this paper we report results of our analysis of CDM projects in China.

Our analysis makes use of data from the project design documents (PDDs) for CDM projects available on the UNFCCC website: this valuable resource provides a wealth of financial and engineering detail on over 2,000 projects. We analyzed all registered projects in our focus categories that were proposed for registration prior to a cut-off date of April 1 2009. Our objectives were to make the most accurate possible assessment, given the limitations of the data, of each project's value to the host country and whether it contributed to the objectives of the CDM; to assess whether the criticisms mentioned above apply to these projects; and to consider whether it is possible to design a market-based or hybrid scheme for this sector that would perform better than the CDM has.

Our results indicate that, in the electricity generation sector, the CDM has partially succeeded. It has not achieved the level of environmental integrity that its designers intended, but has promoted sustainable development.

- The great majority of wind and NGCC projects in our sample were correctly assessed: the issuance of offsets for these projects does not add to global emissions.
- However, the majority of small hydro projects should not have been registered. The issuance of offsets for these projects results in a net increase of global emissions.

- All three types of projects that we evaluated produce significant benefits to human health by cutting harmful emissions of SO_2 and other pollutants. In our view this contributes to the CDM objective of promoting sustainable development.

The focus of the paper reflects our view that electricity generation is the key to emission cuts in developing countries: electricity is vital to development; electricity generation using coal is the largest single contributor to GHG emissions; and the long operational lifetime of a coal-fired power station means that its emissions are effectively locked in to the global emissions total for up to 50 years[90]. We hypothesize that it is possible to design an offset scheme restricted to this sector that would make a significant contribution to reducing GHG emissions, achieve a high level of environmental integrity and provide developing countries with incentives to participate in the global effort to ward off climate change. In our view, the CDM does not deliver those outcomes partly because of its awkward approach to project assessment. The approach adopted in this paper provides a more penetrating assessment of the economics of an offset project and provides an indication of how a redesigned scheme specifically for the electricity generation sector could improve on the CDM, at least in countries where new plant is coal-fired.

Section 2 of the paper provides a description of the CDM program and a review of criticisms made by past researchers. Our methodology is described in section (3); results are in section (4), while section (5) lists our conclusions and some suggestions for further research.

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[90] This statement needs some explanation: it is clear that large reductions can be achieved in many sectors – not least in forestry and land use – while some developing countries make little use of coal in electricity generation. However, our view is that this sector provides a unique opportunity in that the developing countries have a real and well-recognized need for rapid growth in generation capacity to underpin their development objectives. By subsidizing this growth in exchange for the adoption of low carbon generation technologies the developed world can create a win-win situation that is hard to achieve in other sectors.

7.2: The CDM

CDM projects are subject to an elaborate verification process intended to ensure their environmental integrity. Sponsors must show that their project is "additional" – i.e. it achieves cuts in GHG emissions relative to a business as usual baseline and would not proceed in the absence of CDM funding. If a project is profitable without CDM subsidy it will eventually be built: if CERs were issued to that project, the firm that bought them would avoid making cuts in its own operations but no compensating cuts would be made elsewhere because the project would have been built anyway. The net result is that emissions are higher than they would have been without the CDM (Schneider, 2007).

The CDM provides for three approaches to proving additionality: investment analysis, barrier analysis and common practice. Investment analysis demonstrates that the proposed project is financially less attractive than at least one alternative or fails to meet a commercial benchmark, while barrier analysis demonstrates that it faces barriers that prevent its adoption and that do not affect at least one alternative. In some countries (India, for example) most large projects use financial analysis while small projects try to prove the existence of barriers. This is not the case for electricity generation projects in China: of the 460 projects we evaluated, only four relied on barrier analysis.

Common practice demonstrates that a technology is not commonly used in the relevant sector or region. On its own, common practice does not prove additionality – it is used in conjunction with financial analysis or the barrier method as a credibility check (Schneider, 2007). Schneider noted that project sponsors may define the control group of prevailing practice very broadly and the technology under consideration very narrowly. As an illustration, 370 small hydro projects had achieved CDM registration in China as of mid-March 2010 although small hydro is hardly an uncommon practice –

according to the China Energy Databook (LBNL, 2008), more than 44,000 such projects were operational in China as of the end of 1997.

7.2.1. Assessment of emission reductions

The key to calculation of the emissions reductions due to a CDM project is the baseline – the level of emissions that would have occurred if the project did not exist. If the baseline is set too low, global emissions are increased because too many CERS are issued, while if it is too high returns on CDM investment are reduced and presumably fewer such investments will be made. If the baseline is determined correctly, overall emissions do not change but the reductions are shifted from a developed to a developing country (Fischer, 2005). The UNFCCC has adopted a number of standardized methodologies for definition of the baseline – for example, projects in our sample should use the *consolidated baseline methodology for grid-connected electricity generation from renewable sources* (UNFCCC, 2009)[91].

7.2.2. Assessment of sustainability benefits

The UNFCCC's project approval process does not include an evaluation of sustainability: the host countries can define their own criteria and vet projects before proposing them to the UNFCCC. The looseness of both definition and verification of the sustainable development benefits of CDM projects has resulted in frequent criticism of the program. In this paper we define and quantify at least one such benefit.

7.2.3. Project categories

The verification process for additionality and emission reductions has been severely stretched by the need to cater for a very wide range of project types. The charts below provide a breakdown of projects registered as of March 2010 in five categories:

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[91] http://cdm.unfccc.int/UserManagement/FileStorage/HGY3TLRFPQVM016WA4I7XCZD92KE5S

- Our focus category: natural gas combined cycle (NGCC), wind and small hydro.
- Energy efficiency.
- Other energy, including gas from landfill, coal mines and agricultural sources, fugitive gas (mainly flaring of associated gas from oil production), geothermal and tidal energy and combustion of biomass.
- Destruction of industrial gases (HFCs, PFCs and N_2O).
- Other – many of these projects cut CO_2 emissions from cement production (chart 7.1; table 7.1).

Chart 7.1. CDM projects registered - mid-March 2010

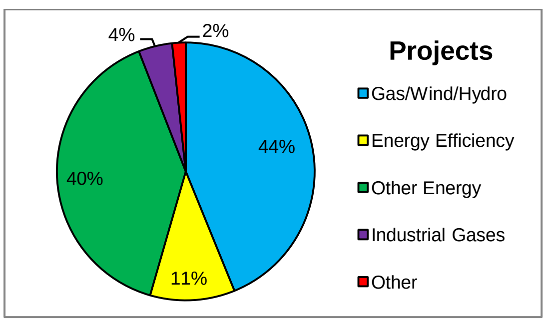


Chart 7.3. CERs issued - mid-March 2010

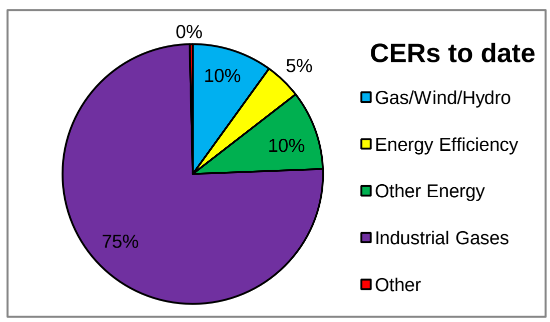
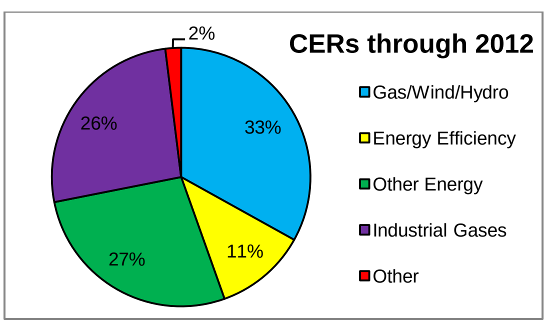


Chart 7.2. Expected cumulative CERs to be issued through 2012



As of mid-March 2010 about 94% of registered CDM projects were energy related, according to the UNEP database[1], while 4% were projects that destroy industrial gases. Our focus sectors account for 44% of registered projects. The relative scale of industrial gas projects – and the speed with which they can be put in place - is demonstrated by the proportions of CERs issued as of the same date: industrial gas destruction – 4% of registered projects – accounts for 75% of CERs issued (Chart 7.3). This imbalance should be reduced as more energy projects come on stream. Based on projects currently in the pipeline, cumulative CERs issued through 2012 will split 26% industrial gases and 72% energy related (Chart 7.2).

Table 7.1. Analysis of Registered Projects (Source: UNEP Risoe)

	Hydro	Wind	Gas	All Other	Total
China	370	165	19	197	751
Rest of World	192	132	26	961	1,311
Total	562	297	45	1,158	2,062

Note: this table includes all projects registered as of March 14 2010. Our sample is limited to projects that were proposed for registration as of April 1 2009.

7.2.4. Criticism of the CDM

Our first objective in this paper is to assess whether criticisms of the CDM apply to projects in our focus category, based on an analysis of actual projects. We are particularly concerned by criticisms that some projects achieve registration that are not "additional" – i.e. they cause a net increase in global GHG emissions (Schneider, 2007; Wara and Victor, 2008).

In the early years of the CDM researchers criticized the flexibility permitted to project developers in choosing how to assess additionality (Fischer, 2005): however in recent years the ongoing process of approval of standardized methodologies for review has reduced the scope for abuse. However, the CDM covers a wide range of projects - a large number of methodologies would be needed to cover them all. The early criticism of excessive flexibility is still valid in some instances. Another of Fischer's criticisms that remains valid is the asymmetry of information in the assessment process. Project data are better understood by investors than by those charged with verification (Fischer, 2005). The UNFCCC's assessors often have no choice but to accept data provided by the project sponsor.

A report published by the NGO International Rivers[92] states that few, if any, of the hydro schemes that apply for CDM registration could realistically claim that they would not be built without CDM credits. More than a third of those approved at the time of the report (November 2007) had been completed at the time registration was granted and almost all were already under construction. In China, which has been a prolific builder of small hydro schemes for over 50 years, the International Rivers report noted no substantial increase in the number of projects under construction since pre-CDM days.

Another common criticism of CDM projects - a lack of "quality" of emissions reductions – in our view applies primarily to industrial gas projects. These projects account for three quarters of total CERs issued to date: they dominate the CDM but do nothing to promote sustainable development – a key objective of the CDM. The gases concerned contribute significantly to the greenhouse effect, but project costs are typically so low compared to the value of CERs issued that the economics of the underlying industrial processes are distorted, creating incentives to game the system that some participants may find irresistible. At worst, projects may have been built to emit GHGs with the objective of generating revenue from the sale of CERs awarded for cleaning them up[93] (Olsen, 2007; Sutter and Parreno, 2007; Wara, 2007).

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[92] See http://www.internationalrivers.org/files/Failed_Mechanism_3.pdf.

[93] Michael Wara noted that "HFC-23 emitters can earn almost twice as much from CDM credits as they can from selling refrigerant gases — by any measure a major distortion of the market" (Wara, 2007). Concerned that countries might actually raise their output of these gases in order to profit from the issue of CDMs, the UNFCCC restricted registration as a CDM project to existing

Suggested solutions to this “quality” problem have included rating of CERs based on sustainability of the projects that generated them (Nussbaumer, 2009; Schneider, 2007) - the Annex 1 country that buys the credits could be required to maintain a specified average sustainability rating. (Resnier et al., 2007) suggested taxation of CER revenues with higher taxes on less sustainable projects. However it is worth bearing in mind Carolyn Fischer’s view that it is arguably better to lower the cost of emissions reductions by encouraging participation in the CDM by developing countries than it is to devise ever more complex rules for project approval, particularly in view of the nascent institutions and governance systems in many of these countries (Fischer, 2005).

If the baseline is determined correctly, the CDM does not change overall emissions but the reductions are shifted from a developed to a developing country. The implicit assumption is that emissions can be cut more cheaply in the developing world so the shift enhances overall welfare by reducing the overall cost of GHG reduction (Fischer, 2005). Some researchers have questioned this assumption. Sathaye and Phadke (2006) compared the costs of cutting emissions of CO_2 in India and the US by switching from coal to natural gas fired generation(Sathaye and Phadke, 2006). They concluded that emission reductions achieved in this way are more expensive in India, mainly because of the high capital cost of plants based on imported technology. The implication of their research is that the CDM, at least in this narrowly defined area, reduces overall global welfare while enriching the provider of the technology.

During the early days of the CDM, many researchers were concerned that projects would be burdened with high transaction costs. This issue has turned out to be less important than was feared, partly because the carbon price set by the EU ETS has been high enough that for all but the smallest projects, revenues from the CDM have been

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plants. However in 2005 the UNFCCC weakened this ruling and allowed new plants to register, subject to some restrictions.

significantly higher than transaction costs. The level of these costs seems to have been reasonable, though there are likely to be variations across countries and by project size (Michaelowa and Jotzo, 2005).

Of more concern are the conflicts of interest inherent in the CDM format. An issue that has been frequently raised is that the designated operational entity (DOE – the consultant that evaluates a CDM project) is selected and paid by the project participants (Schneider, 2007). Even worse, in our view, are the conflicts created when host country governments own assets that compete with CDM projects. Governments must monitor and enforce domestic regulations - particularly important in the electricity sector are tariff setting, environmental regulation and the regulation of market competition (Williams and Kahrl, 2008).

Finally, it is clear that the UNFCCC needs to invest in capacity building in Non-Annex 1 countries to ensure effective monitoring and enforcement of domestic regulations with direct and indirect relevance for the CDM projects (World Bank, 2006).

7.3: METHODOLOGY

We define a baseline generation plant for each regional grid and use the generation cost of the baseline plant as basis for calculation of the marginal abatement cost (MAC) for CDM projects in the same region (China excluding the Tibet Autonomous Region has six grid regions). A new plant is the appropriate baseline as electricity demand in China is growing. The baseline plant is therefore the marginal new conventional plant, which is a 1200MW supercritical coal fired unit (the IEA report *Cleaner Coal in China* noted that about 60% of all newbuilds in China are large supercritical units (IEA, 2009)). Its location within the region matters because the cost of transporting coal from mine to power station is a significant element of generation cost. In each grid region we determine – somewhat subjectively – the likely location of a new plant, either at the mine (North and Northeast regions) or close to some concentration of consumers.

We define the MAC of project p as:

$$MAC_p = \frac{C_p - C_b}{E_b - E_p} \quad (1)$$

where C_p is the generation cost per unit of electricity generated by the project and C_b is the cost per unit for the baseline project. E_p is the volume of emissions in CO_2 equivalent per unit generated by the project and E_b is the same parameter for the baseline project. Our approach to calculation of these parameters is described below.

7.3.1. The sample of CDM projects

Our sample comprises 100% of grid-connected generation projects in China based on wind turbines, small hydro or NGCC technology that were proposed for registration as CDM projects prior to a cut-off date of April 1 2009 and had achieved registration by March 1 2010. Of the 460 projects, twenty six could not be used as the PDD did not provide sufficient data[94], leaving a usable sample of 434 projects – see table 7.2.

Table 7.2. Details of Sample (Source: UNEP Risoe)

Project Type	Registered	Sample
Commercial scale gas	19	19
Wind farms	136	117
Hydro	305	298
Insufficient data	(26)	
TOTAL	434	434

[94] Of the 26 unusable projects, 4 used barrier analysis to assess additionality, so the PDD did not need to provide financial data; all the others used investment analysis but provided insufficient information to permit a proper re-evaluation. For example, four projects provided data in US Dollars but did not include an exchange rate. For these projects one can calculate a generation cost in USD but it is not possible to make a valid comparison with the baseline generation cost, which is in RMB.

The 26 unusable projects included 19 wind farms and seven small hydro schemes. They were mostly early projects: they included 20 of 28 projects proposed for registration through November 2006 but only six out of 432 projects proposed subsequently.

7.3.2. Method of calculation: generation cost and emissions saved

The **cost of electricity** can be calculated from the energy content of the fuel used, the delivered cost of the fuel and the characteristics of the plant. The formula we use is:

$$Generation\ Cost\ per\ MWh = Fuel\ cost + capital\ cost + operating\ cost$$

Where capital cost is an annual capital charge[95] based on an appropriate discount rate (see comments below on risk) and operating cost is the total cash operating cost of the plant excluding fuel. Both capital and operating cost are expressed as cost per megaWatt hour (MWh) based on the plant's expected annual output, but we implicitly treat these costs as fixed – any costs that are clearly volume-related (such as pre-treatment of coal) are included in the fuel cost per ton. The efficiency of the baseline plant is based on figures in (MIT, 2007)[96] while capital and operating costs are obtained from Chinese official sources[97]. For the CDM projects we use the figures given in the PDD. We assume that all cost elements remain constant in real terms. As mentioned below, our objective is to evaluate projects based on their value to the host country, not on the return to investors. We therefore exclude from our calculations all taxes, tax

[95] Also called equivalent annual cost. It is "the annual cash flow sufficient to recover a capital investment, including the cost of capital for that investment, over the investment's economic life" (Brealey et al., 2006).

[96] The assumed heatrate of a supercritical plant burning Chinese coal is 2,098 kcal/kWh.

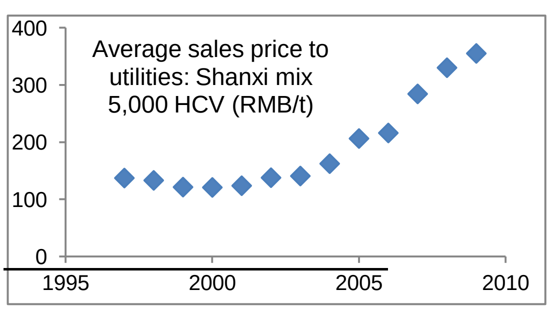
[97] *Thermal Power Engineering Design Reference Cost Index* produced by the China Institute of Power Planning and Design. This appears not to include insurance – we used figures from a number of PDDs. We also added the additional costs of flue gas desulfurization obtained from (You & Xu, 2010).

credits and subsidies, which we see as primarily intended to influence the return to investors.

In principle, generation cost should be adjusted for cost of transmission, particularly for wind and small hydro projects. A proper evaluation of these costs would require a complex simulation of the Chinese grid. However, many small hydro schemes are located in remote areas that are undersupplied with electricity: the project might well be the lowest cost means of supplying the area and actually save on transmission costs. On balance, it seems reasonable to make no adjustment. Wind projects, however, are essentially suppliers to a regional grid and the cost of connection to the grid cannot be ignored. Our adjustment for wind intermittency (see below) includes an element for added transmission costs.

Our estimates of **fuel prices** are based on figures for the pithead price of coal for power generation in 2006 given in the China Energy Databook (LBNL, 2008). We assume that this price applies to Shanxi mixed coal with a GCV (gross calorific value) of 5000 kcal/kg, which we use as our standard. From 2007 coal prices were liberalized – generators negotiated contract prices for much of their supply and bought the rest at spot-based prices. Precise figures are not available – not least because large volumes of coal were produced by mines that were operating illegally - but we have made what we believe are reasonable estimates – see chart 7.4.

Chart 7.4. Pithead Price of Shanxi coal (RMB/ton)



To this pithead price we add preparation (washing) costs[98] obtained from (You and Xu, 2010) and estimated rail and sea freight from Shanxi to the power plant location.

[98] We assume that 100% of coal is washed to reduce sulfur and ash content.

For gas prices, we have no alternative but to take the price for each project from the PDD and keep it constant in real terms. Chinese gas imports are purchased under long term contracts and contract price formulae (usually there is a link to oil prices) are confidential. In any case, only about half the gas-based projects in our sample pay international prices and the relationship of domestic gas prices to international (LNG) prices is not clear to us.

For the baseline coal-fired plant and for CDM plants fueled by natural gas we can estimate **emissions of CO_2 per MWh** from efficiencies and operating characteristics. We assume the default emissions factors published by the IPCC[99]. For wind and hydro, operational emissions are zero. We follow a UNFCCC rule in ignoring leakage emissions (emissions of greenhouse gases that result from operation of the project or the baseline plant but do not occur at the plant location_- examples include emissions of methane from a coal mine during operations, or emissions related to energy used to run the pumps that pressurize gas pipelines). The UNFCCC rule is to ignore negative leakage (when leakage from a project is less than leakage from the baseline plant). All projects that we consider have negative leakage.

7.3.3. Project risk and related issues

The levelized cost methodology is the traditional approach to project evaluation in the electricity generation sector. Projects are compared on the basis of generation cost, with expected cash costs over the project life discounted to take account of the time value of money. This is a rational way to choose between investments when cash flows are predictable or when cost-plus regulation effectively equalizes risk between projects; however, it can produce perverse results when different technologies have different risk

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[99] Coal (other bituminous): 94,600 kg CO_2 per TJ; natural gas 56,100 kg CO_2 per TJ.

profiles (IEA, 2005). For example, a project with high capital costs but low operating costs might have a very different risk profile to one where the opposite is the case.

Even in well-established power markets, the move away from a risk-leveling approach to regulation is reducing the value of levelized cost as a decision tool (IEA, 2005). Its relevance in the fast-changing Chinese market is somewhat dubious. A commercial firm contemplating an investment would very likely estimate the project return in a number of scenarios, or calculate a wide range of sensitivities, and would use a project hurdle rate that reflected the perceived risk. In a paper such as this one, it is not feasible to apply sophisticated risk analysis methodologies to each and every project. Our methodology balances simplicity – so we can use the data available from the UNFCCC– and recognition of risk differentials.

The investment analysis method of assessing CDM projects compares the project's financial return with some benchmark. The benchmark rate ("hurdle rate") enters our generation cost calculation as a required return on capital, used in calculating the annual capital charge. In broad terms we can reflect differences in the risk profiles of technologies by using different hurdle rates. For coal and gas fired plants we use the standard set by the Chinese government,[100] which is an internal rate of return (IRR) of 8% in real terms - more or less in line with benchmarks used by major energy companies in the developed world. For wind and small hydro projects we adjust that rate to reflect the lower proportion of debt financing that is appropriate for a project with intermittent revenues. For these projects we use 8.7%, which allows for a move from (say) 70% debt financing to 50%. The adjustment method used is taken from (Brealey et al., 2006).

[100] The PDD for CDM project No 1734 quotes the Chinese *Interim Rules on Economic Assessment of Electric Power Engineering Retrofit Projects* on this subject. Small hydro projects in China are assessed using a 10% hurdle rate: we have not followed this as we regard the higher rate as a policy-based incentive rather than based on a risk calculation.

Our base case assessments are based on a 40 year life for all projects. This is realistic for coal, gas and hydro projects but less so for wind (though (IEA, 2005) generally assumes the same life for all types of plant). As a sensitivity, we recalculate generation cost for wind projects assuming a 20 year life.

Wind does not always blow: a grid that obtains a significant amount of electricity from wind incurs costs to maintain a constant supply voltage and frequency. This is becoming a problem for China, where wind is the fastest growing generation technology[101]. There is no doubt that it adds to China's electricity supply costs.

"Integration cost is the extra investment and operational cost of the non-wind part of the power system when wind power is integrated" (Holttinen et al., 2009). It can be divided into **balancing costs** (additional operating costs) and **investment costs** (investment in non-wind backup capacity and in extensions to the grid). Estimation of integration costs requires a hugely complex exercise in simulation: we can obtain some idea of potential costs in China by reviewing simulation exercises made in other countries.

- Large grids or those with good connections to their neighbours have lower **balancing costs**. The IEA Wind study (Holttinen et al., 2009) found costs of about €0.3/MWh in Norway, which has good interconnections with grids in neighbouring countries. The UK - a relatively small and isolated market – would incur balancing costs of €1.4/MWh with wind contributing 5% of supply, rising to €3.4/MWh with 20% of supply from wind. The Chinese grid is huge, but linkages between regions are poor.

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[101] Chinese wind capacity doubled in 2008 for the fourth successive year; in 2006 it provided 0.1% of China's electricity supplies (Williams and Kahrl; 2008); it now provides 1.3% (Louis Schwarz, writing in *Renewable Energy World* on March 10 2009 - see www.renewableenergyworld.com). The Chinese government, as of end-June 2009, was said to be considering setting a target for renewable energy to provide up to 20% of total electricity supply by the end of 2020.

We deduce that balancing costs are minimal in most of the country but high in some areas with concentrations of wind generation capacity.

- The two Chinese grid operators have incurred huge **investment costs** in recent years, but our view is that these investments are largely due to rapid demand growth and greater need for flexibility[102]. "Costs related to the intermittency of wind generation should not be confused with the costs of adapting the grid to more efficient operation with private sector participation and more decentralized decision making" (IEA, 2005).

Our assessment is that wind intermittency costs in China are high but will be temporary. Balancing costs in certain isolated regions are currently significant but will be far lower as connections between grid regions improve. High investment costs are mainly related to expansion and the need for flexibility, though some new transmission links may be brought forward to cope with wind-related problems. As a rough estimate, we include in our model an integration cost for Chinese wind generation of €1.5 (US$2.0) per MWh equal to the balancing cost incurred by the relatively isolated UK grid with 5% wind penetration.

Two of the gas-fired plants in our sample sell steam to district heating systems. We net off from plant costs the revenue received for steam supplies, but our MACs for these plants are high, implying that the additional costs are not fully offset by revenues received. Note also that our figures for emissions saved by these plants are

[102] Every electricity grid needs backup to meet sudden peaks in demand, or in case a plant has to shut down for operational reasons. If we assume (reasonably) that these operational risks are not correlated with changes in wind strength, small amounts of wind generation have a negligible effect on overall downtime risk. (Holttinen et al, 2009) concluded that an efficient grid that can access backup generation capacity over a wide area can handle wind generated electricity up to 20% of total supplies with little or no additional investment. In most of China, the problem is that the grid is inefficient and demand is growing vertiginously.

underestimated because the alternative source of steam for a municipal heating system is probably a small coal fired boiler - many such boilers in China are major sources of local pollution as well as GHG emissions. Because of these distorting factors, we have excluded these plants in calculating averages for Chinese NGCC plants.

7.3.4. Comparison of our methodology and that required by the UNFCCC

Before registering a CDM project, the UNFCCC Executive Board must verify its additionality (i.e. that it would not be built without the CDM subsidy and will achieve a real reduction in emissions of GHGs). Most large projects demonstrate additionality by the financial analysis method – i.e. they estimate the financial return *to the investors in the project* and demonstrate that some alternative plant configuration would give a better return. A weakness of this approach is that the principal determinant of a project's return is its feed-in tariff - the price at which it sells power to the grid. In many countries the government effectively decides which projects are built and also sets the tariff. The UNFCCC methodology verifies only whether the government has allowed the investors to make a profit. If anything, the government has an incentive to set a low tariff to ensure the project's eligibility for the CDM, as the CER revenue stream adds to national income.

Our preferred measure, the MAC, is based on the cost of electricity generated by the project. A generation cost lower than baseline provides a benefit to *the host country*: a rational government should seek to capture that benefit by setting tariffs that allow low cost projects to be profitable. This implies that a project with a generation cost below baseline (i.e. a project with a negative MAC) would be built even without CDM funding and is therefore not additional[103].

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[103] The UNFCCC's Executive Board (EB), which reviews CDM projects, has recently been paying more attention to tariffs. At its February 2010 meeting, an unusually large number of projects were put under review – i.e. denied immediate registration. As of March 8 2010, 36 of these

In fact, we find a significant number of CDM projects in China with negative MACs. We also find projects with MACs that are higher than observed CER[104] prices. Theory indicates that, over the long term, the market price for CERs should be close to the cost of cutting emissions in Annex 1 countries as emitters arbitrage between making cuts and buying permits. If MACs are consistently higher than the value of CERs generated, the implication is that emissions cuts could be made more cheaply in annex 1 countries. This contradicts the rationale for the CDM that emissions cuts in a developing country cost less (although Sathaye and Phadke concluded that the cost of emissions cuts achieved by substituting gas-fired plants for coal is higher in India than in the United States (Sathaye and Phadke, 2006)).

7.3.5. Method of calculation: sustainability benefit

As the host government decides which projects can be proposed for CDM registration, one would expect that a project with higher than baseline generation cost after taking account of CER revenue would be denied support. As large numbers of such projects are proposed for registration, governments may be considering project benefits beyond simply generation cost. The value of a project's contribution to sustainable development may provide an explanation.

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projects were still under review, of which 25 were wind or hydro projects in China for which the EB had questioned the tariff applied. In our view, this amounts to second-guessing the Chinese regulator based on inadequate information. It would be better to look directly at generation costs (and insist on adequate information being provided).

[104] Strictly speaking, the EU Emissions Trading Scheme (ETS) is based on EUAs (EU Allowances) while CDM projects receive CER (Certified Emission Reductions) credits. CERs and EUAs are interchangeable for purposes of compliance with the EU ETS and trade on the same markets. Logically their prices should be identical, but in practice the market price of CER futures is €1 - €2 below that of EUA futures, either because of lower liquidity or greater risk of non-delivery. For both instruments, prices quoted in this paper are futures price for December 2009 settlement quoted on the European Climate Exchange (ECX).

The UNFCCC does not define what "sustainable development" means, which is hardly surprising – it is hard to define and harder to quantify. However, a project that generates electricity using a zero or low emission technology reduces the cost to the Chinese economy of health problems related to pollution from burning coal. In principle, the improvement to health can be valued.

A simple approach to quantifying the value of this benefit is to calculate (Resnier et al., 2007):

$$Ext_i = \sum_p Em_{pi} * Dc_p \qquad (2)$$

Where, (Ext_i) is the value of external damage avoided per kilowatt hour of electricity generated by project i; (Em_{pi}) is the level of emissions of each pollutant p avoided per kilowatt hour of electricity generated by project i and (Dc_p) is the damage cost per unit of emission of pollutant p.

- **Avoided emissions**: emissions of SO_2 and primary particulates (fly ash) can be calculated from the sulfur and ash content of the coal - our calculations are based on Shanxi coal with a sulfur content (after washing) of 0.74% and an ash content of 10.04%. Our baseline plant is fitted with flue gas desulfurization (FGD) that removes 85% of SO_2 - a conservative assumption in that, while all new large power plants in China must be fitted with FGD, their profitability can be maximized by simply not running it. There are indications that this is indeed happening (Williams and Kahrl, 2008). We assume that 99.5% of fly ash is removed from the flue gas by electrostatic precipitation and that new power stations use the best available low NO_X burner technology but not selective catalytic reduction (SCR) as required for new sources in the US. For gas-fired plants, we assume zero emissions of SO_2 and TSP (total suspended particulates).
- Our estimates of Dcp - the **damage cost per ton of pollutant** - are based on estimates of externality cost per ton for TSP, SO_2 and NO_X in (Meier, 2003). Meier's

methodology is described in *Economic Evaluation of Environmental Impacts: a Workbook* (Asian Development Bank, 1996). His dose-response functions are from US sources, notably (Pope et al., 2002; Pope et al., 1995) and unit values for damages were adapted from a study made in the early 1990s in New York State (Rowe et al., 1995; Rowe et al., 1996) using the benefit transfer methodology (Krupnick et al., 1996). Valuations are based on specific endpoints such as all cause mortality, estimated using the willingness to pay (WTP) approach.

In recent years researchers have cast doubts on some aspects of these methods: the use in a developing country of dose-response functions from the US has been questioned and the validity of benefit transfer has been disputed (Hammitt and Zhou, 2006; Liu et al., 1997; Ostro, 2004; Wang and Mullahy, 2006); some researchers have considered using quality adjusted life years (QALYs) or years of life lost (YOLL) rather than mortality (Kenkel, 2006); WTP is preferred in the developed world, but the alternative adjusted human capital (AHC) approach has been more widely used in China (Zhang et al., 2010).

Meier estimated unit damage costs per ton of pollutant for 31 Chinese states and municipalities. We allocate these states and municipalities to grid regions and calculate a population weighted average for each grid region, updated for changes in population and per capita GNI since 1999. Table 7.3 shows the data for New York State and Meier's values for Shanghai.

Table 7.3 Unit damage costs (1999$/1000ton/person)

	TSP	SO_2	NO_X
New York State (Rowe et al)			
Local	0.212 – 0.317	0.042 – 0.085	0.063 – 0.085
Regional	0.106 - 0.317	0.021 – 0.042	0.042 – 0.063
Distant	0.042 – 0.085	0.001 – 0.021	0.011 – 0.021
Shanghai (Meier)			
Local	0.023 – 0.034	0.005 – 0.009	0.007 – 0.009
Regional	0.006 – 0.019	0.001 – 0.003	0.003 – 0.004
Distant	0.001 – 0.002	0.000 – 0.000	0.000 – 0.000
Shanghai – total externality (1999$/ton)	2339	479	611

Source: Meier P., 2003

Note: data from Rowe et al were adjusted to 1999$ by Meier.

Our 2007 externality valuations are shown in table 7.4. They are clearly subject to a wide margin for error but they provide an indication of the health benefits of low-emission generation technologies. The criticisms in the papers mentioned above indicate that our estimates are likely to be on the high side.

Table 7.4. Externality valuations (2007 RMB/ton)

Grid Region	Population (m) (2007)	TSP	SO_2	NO_X
China Central	367	14,379	3,806	3,609
China East	224	33,395	8,865	8,378
China North	255	22,214	5,718	5,617
China Northeast	121	7,959	2,077	1,998
China Northwest	96	4,475	1,197	1,116
China South	225	9,799	2,510	2,464

7.4: Results

7.4.1. Generation Cost and MAC

Table 7.5. Generation cost and MAC by year and project type

		Number of Projects	Generation Cost (US¢/kWh)		MAC (US$/$tCO_2e$)	
			Mean	Standard Dev'n	Mean	Standard Dev'n
Coal	2006	N/A	2.9			
	2007	N/A	3.5			
	2008	N/A	4.2			
	2009	N/A	4.5			
Wind	2006	4	6.4	1.5	40.6	19.4
	2007	41	6.7	0.9	38.0	11.1
	2008	61	7.2	1.1	37.0	11.6
	2009	11	8.5	1.1	49.5	11.6
Hydro	2006	8	2.5	0.8	(5.0)	10.8
	2007	56	2.5	0.7	(13.1)	9.7
	2008	212	2.8	1.0	(19.8)	12.3
	2009	23	3.6	1.4	(12.7)	15.6
Natural Gas	2007	9	4.9	1.2	27.5	18.7
	2008	7	6.1	0.6	23.9	13.1
	2009	3	6.5	N/A	26.5	N/A

Notes: (a) The figures shown for coal are the averages of China's six grid regions.

(b) Average costs for gas exclude two gas-fired combined heat and power plants.

- Small hydro is significantly cheaper than the coal baseline - its average MAC is negative for all years (though costs for these projects are site-specific so the range is wide) (Table 7.5). We conclude that the majority of small hydro projects should be assessed as not additional. Small hydro has historically accounted for a significant share of Chinese power generation: according to the China Energy Databook (LBNL, 2008) the number of small hydro stations in China at the end of 1997 was over 44,000 - clearly the Chinese government thought these stations were worth building even without the CDM subsidy.

- As a sensitivity, we looked at the effect of varying project life for wind only as our standard assumption of 40 years is probably too generous for this project type. The increase in costs when the total investment must be spread over a shorter life is significant (Table 7.6).

Table 7.6. Effect of changing project life (wind projects)

Project Life	40 years		20 years	
	GenCost (US¢/kWh)	MAC (US$/t$CO_2$e)	GenCost (US¢/kWh)	MAC (US$/t$CO_2$e)
2006	6.4	40.6	7.4	51.4
2007	6.7	38.0	7.7	48.8
2008	7.2	37.0	8.2	48.8
2009	8.5	49.5	9.8	63.4

- The European carbon price peaked at €32.9 (US$40.6) in April 2006, then collapsed. Over the period of this study it has ranged between €32.9 and €8.2, with a mean of €20.0 and a standard deviation of €4.6 (US$26.6 and US$6.1 at the average exchange rate over the period). An average Chinese wind farm that benefited from the CDM subsidy would have been a marginal economic proposition at the peak, with CER revenues exactly equal to its generation cost disadvantage. However, at the price levels that have held since May 2006 one has to assume that the Chinese government, which has encouraged an impressive surge of investment in wind generation, sees some value in diversifying the country's mix of generation technologies that is not captured by our study. This could be that a wind generation plant uses essentially no water – a coal-fired plant uses water for cooling and also in its flue gas desulfurization system. China has experimented with air cooling for power stations in the water-short North of the country but air cooling significantly reduces the efficiency of a plant. If the government is looking to the time – possibly not far into the future – when the marginal generation plant in Northern China is air-cooled, it is looking at a wind power MAC significantly lower than our estimates.

- Generation costs for all project rose over the period. Higher fuel costs are the main cause for coal and gas-fired plants, while capital cost inflation affects all project types. However, for all categories of CDM project, a declining plant load factor (PLF) significantly raised unit costs. PLF is the ratio of actual output to the plant's maximum theoretical output. A low PLF means that plant fixed costs, including capital recovery, are spread over a smaller amount of output (we assumed an 85% PLF for the coal-fired baseline plant) (Table 7.7).

Table 7.7. Average PLF by year (%)

	Wind	Hydro	Gas
2006	25.0	49.0	N/A
2007	25.2	47.0	41.0
2008	25.6	45.0	40.0
2009	23.9	42.0	35.0

The sharp decrease for wind in 2009 could reflect grid problems caused by rapid growth in wind capacity. According to a report in Interfax China Energy Weekly dated September 1, 2009, the power grid in Inner Mongolia – China's most favored wind region – is unable to cope with a surge of wind plant construction. Wind power creates control problems for grid operators (see section 3 of this paper: methodology) and wind is expected to account for 15% of electricity supplies in Inner Mongolia by the end of 2009. The decreasing PLFs for hydro and gas are harder to account for. A simple explanation is that, as our project data are plan rather than actual figures, Chinese engineers today are using less optimistic assumptions in the light of experience with earlier projects. Our project data could be biased as our sample cut-off (projects proposed by April 1 2009 and registered by March 1 2010) excludes eight projects proposed by the former date that had not achieved registration by the latter. As generation cost is a key factor in the investment analysis method of determining additionality, further research is needed on this issue.

We compared our generation cost figures calculated from PDD data with estimates in Projected Costs of Generating Electricity: 2005 Update (IEA, 2005), which contains data for plants currently under construction or planned, mainly in OECD countries. Differences in assumptions between the two sets of data are too great to allow of meaningful analysis, but a very obvious difference is that, for all technologies, we find lower construction costs in China. For coal and hydro the difference is startling – Chinese construction costs per kilowatt are less than half OECD levels. Our estimate of the construction cost of a coal-fired plant in China is taken from the Thermal Power Engineering Design Reference Cost Index produced by the China Institute of Power Planning and Design. Very similar figures are given in (Lan et al., 2007) and in a report from the China Power Regulatory Commission (see http://www.chinamining.org/News/2006-07-20/1153374414d105.html). The Chinese cost figures owe something to low Chinese wages, but an important reason why the figures are so low must be the learning curve effect of building these plants in very large numbers.

This indication that capital costs are lower in China than in the OECD contrasts with the findings of Sathaye and Phadke that the cost of cutting CO_2 emissions in India by substituting gas-fired generation for coal was higher than in the US, largely because of the high capital cost of imported equipment. Their costs for India were based on figures provided to the government for regulatory purposes, while their US data are from an EPA database (Sathaye and Phadke, 2006). We will extend our analysis to India in the near future: for the present we note that the economics of emissions cuts may be very different in the two countries.

Table 7.8. Comparison of generation cost estimates

	Year	Generation Cost US¢/kWh	Construction Cost US$/kW
Coal (without CCS)			
(IEA, 2005)	2003	4.4	1,312
This Paper	2006	2.9	531
Gas (NGCC)			
(IEA, 2005)	2003	5.1	644
This Paper	2007	4.9	440
Wind			
(IEA, 2005)	2003	8.1	1,430
This Paper	2006	6.4	1,215
Hydro			
(IEA, 2005)	2003	7.9[a]	2,055[a]
This Paper	2006	2.5	894

Note: (a) Average excluding outliers (two projects in Germany and Japan).

7.4.2. Sustainability and the valuation of health benefits

A common criticism of the CDM is that it does not boost sustainable development in the host countries. The net effect on sustainability of, for example, a hydro scheme, is arguable, but all the projects that we analyze clearly produce significant and quantifiable benefits to human health due to their lower levels of pollution compared to coal-fired plants. In fact, this is only one of a number of ancillary benefits of these projects: they have lower water usage per kWh generated (particularly important in Northern China); they bring employment to rural areas and they advance rural electrification. Most of these effects on sustainability are practically impossible to quantify, but we have attempted to quantify the health benefits.

Table 7.9. MAC adjusted for health benefits of CDM projects (2007 data)

US$/t$CO_2$e	Mean MAC	Mean Benefit	Benefit as % of MAC	Adjusted MAC
Wind	38.0	2.0	5.3%	36.0
Hydro	(13.1)	1.3	N/A	(14.4)
Natural Gas	27.5	2.7	9.8%	24.7

Table 7.9 above shows unweighted averages of the health benefits for the three types of projects. Benefits are specific to the region in which a project is located - a cut in pollution in a region with high population will have a greater absolute financial effect because of the greater number of people affected. In China, some wind farms and most gas-fired power stations are located in heavily populated coastal regions, while most hydro projects are in sparsely populated provinces such as Yunnan. We believe that this accounts for the differences in value of health benefits between project types (population by region in 2007 is shown in table 7.4).

We can use our cost and benefit figures to analyze whether these projects provide overall benefits to their host countries. Table 7.10 below lays out the overall costs and benefits of each type of project per ton of CO_2e avoided, using 2007 data. The CER revenue shown is the average EUA price since April 2005.

Table 7.10: Overall cost/benefit analysis of projects

US$/t$CO_2$e	Additional Generation Cost	Benefit to Health	CER Revenue	Net Cost / (Benefit)
Wind	38.0	2.0	26.6	9.4
Hydro	(13.1)	1.3	26.6	(41.0)
Natural Gas	27.5	2.7	26.6	(1.8)

- Wind generation produces a negative net benefit. We suggest above that the Chinese government may be motivated by some benefit of wind power that is not in our analysis: as many of these projects are located in the North of China – a region that is increasingly plagued by water shortages – this may be wind's zero water requirement in operation.
- Natural gas plants are close to neutral in net benefit terms, without taking into account the value of the added flexibility that they bring to the grid.
- Hydro schemes in China are so profitable that they should not be in the CDM at all.

7.5: Conclusions and directions for future research

Our principal objective in this paper is to focus on one key sector in one country and ask whether the criticisms that have been made of the CDM apply here, and whether any problems identified apply specifically to the CDM or to offset schemes in general. If the former is the case, is it possible to salvage the positive features of the CDM in a better designed offset scheme?

As regards the first of these questions, CDM projects in this sector receive a mixed report:

- Most wind and NGCC projects in our sample are additional - the issuance of CERs for these projects does not add to global GHG emissions (though it may increase the global cost of emissions cuts).
- The majority of small hydro projects are not additional. Other things being equal, the issuance of CERs for these projects damages the environment by allowing a net global increase in GHG emissions.
- All three types of projects produce significant benefits to human health by cutting harmful emissions of SO_2 and other pollutants. In our view these projects achieve the CDM objective of promoting sustainable development.

The problems identified are partly due to the inadequacy of the UNFCCC approach to assessing additionality. An offset scheme designed for a specific sector such as power generation could focus on the impacts of projects in that sector, providing insights that the standardized CDM methodologies would miss. This could enhance confidence that the sector-specific scheme achieves the impact that its designers intended and does not create perverse incentives.

It is not our intention in this paper to make detailed policy proposals, second-guessing the outcome of international negotiations. However the electricity sector is vital to the development goals of countries such as China and India and offers the possibility of an international agreement to limit GHG emissions. By combining an offset scheme with direct funding of investment and technology transfer, it would be possible to underpin development of these countries by ensuring adequate supplies of electricity at the lowest possible cost while maximizing the use of zero or low carbon generation technologies. To work effectively, such a scheme would have to transfer significant funds from the developed to the developing world. To obtain buy-in from the countries that would provide the funds, it would have to be based on analytical methodologies that inspire confidence.

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8: Electricity generation costs in India – India at a crossroads[105]

8.1: Introduction

India faces formidable challenges in meeting its energy needs – to quote the opening statement of the country's Integrated Energy Policy (IEP).[106] The IEP is based on the premise that coal will remain India's main energy resource for the foreseeable future. This view is widely held – the IEA forecasts that coal demand in India will more than double between 2010 and 2035. However India's rate of economic development and the resulting increase in electricity demand (the power sector accounts for more than 60% of the expected increase in coal demand) has outstripped the production capability of Indian coal mines:[107] much of the increase will be met by imports. (IEA, 2011)

Growth of this scale would sharply increase India's GHG emissions, putting in question the country's commitment to reduce the carbon emissions intensity of its GDP by 20%-25% from 2005 levels by 2020, while the increase in imports would impact both energy costs and energy security. There could also be serious consequences for human health: a recent RFF Discussion Paper provides preliminary estimates of the impact of India's coal fired power stations on health (Cropper et al., 2012).

To avoid – or at least mitigate - these negative consequences, there is a need for policies aimed at maximizing the proportion of India's generation capacity that is based on low or zero carbon technologies – nuclear or renewables. India has no shortage of plans to increase investment in both. An interim report by an expert group set up by India's

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[105] By Ian Partridge: submitted for publication as (Partridge, 2012a).

[106] See planningcommission.nic.in/reports/genrep/rep_intengy.pdf. The Integrated Energy Policy was published by the Government of India in August 2006 (accessed 6/27/2012).

[107] According to an article in The Economic Times (Mumbai) dated June 6, 2012, the state owned Coal India Limited has warned its power sector customers that it can supply only 60% of their requirements: it hopes to be able to increase this to 80% of requirements within a few years.

Planning Commission set targets based on an analysis of how India might meet its commitment cut the emissions intensity of its GDP (Planning Commission, 2011).[108] The Strategic Plan[109] published in February 2011 by the Ministry for New and Renewable energy (MNRE) contained similar targets together with more ambitious "aspirations" for grid-connected renewable generation. For wind generation, the target – to be reached in 2022 - is 38.5 GW, with an aspiration of 45 GW - installed capacity at the end of 2010 was 13.1 GW. For small hydro the target is 6.6 GW, the aspiration is 8.0 GW and installed capacity in 2010 was 2.9 GW; for solar the target and the aspiration are both 20 GW and 2010 capacity was only 18 MW. These figures do not include large hydro (defined as above 25MW capacity), which is an important source of power for India with installed capacity of 37.4 GW in 2010 Off-grid generation is also excluded, though it could make a significant contribution to the country's push to bring electricity to villages that currently have no supply. India's National Solar Mission – a government initiative set up to encourage investment in solar power – has a target of 2.0 GW for off-grid generation – the MNRE Strategic Plan suggests that this could be doubled.[110]

Estimates of India's ultimate renewable energy potential cover a wide range: for wind, the figure published by the Centre for Wind Energy Technology (CWET) - an R&D arm of the MNRE - is 103 GW at 80m hub height;[111] however a recent study by the Lawrence Berkeley National Laboratory gave a range of figures from 2,006 GW at 80m hub height

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[108] Its proposals have been criticized as unambitious by the Centre for Science and Environment – a Delhi-based NGO: see http://www.cseindia.org/node/2604 (accessed 6/27/2012).

[109] See http://mnre.gov.in/information/policies-2/ (accessed 6/27/2012).

[110] Rapid growth in renewable energy capacity means that the Strategic Plan figures for installed capacities are already out of date: for solar, a MNRE press release dated May 11 2012 (http://pib.nic.in/newsite/erelease.aspx?relid=83632) stated that 979 MW of grid-connected solar PV has been installed. The most recent announced figure for wind capacity in India is 14.9 GW at the end of August 2011 (source: MNRE).

[111] http://www.cwet.tn.nic.in/html/departments_ewpp.html (accessed 4/25/2012).

to 3,121 GW at 120m (Phadke et al., 2012). The accepted figure for the country's hydro potential (both small and large scale) is 149 GW[112] while the potential for solar is usually simply described as huge. One could raise questions about some of these estimates, but it seems reasonable to conclude that a very large increase in renewable generation capacity would enable India to at least partially escape the consequences of reliance on imported coal; and that the potential for such an increase clearly exists.

The economic consequences of such an increase are not so clear. In this paper I present a set of internally consistent estimates of generation costs for a number of renewable technologies and for coal fired plants in India, with projections of likely cost changes to 2020. The projections for coal fired plants use realistic coal price scenarios while those for renewables draw on a learning rate analysis for both wind and small hydro, based on cost data for registered CDM projects.[113] The latter analysis was presented in an earlier paper (Partridge, 2012b). Some cost estimates and comments on solar PV are included, but as only two Indian projects have achieved CDM registration (as of July 2012), these are based on figures published by McKinsey (Aanesen et al., 2012). I have not found any similar set of projections for generation costs in India using both renewable and conventional technologies – the paper thus makes a unique contribution to debate about India's energy policy.

The conclusions presented below cast doubt on the primacy of coal in the Indian energy scene. A reliable fallback position for India's energy policy makers has always been that coal, despite its disadvantages, is both cheap and plentiful. This position is no longer tenable: high cost imported coal is now the marginal energy source for India. If

[112] http://www.nhpc.gov.in/English/Scripts/Hydro_Scenario.aspx (accessed 08/08/2012).

[113] The Clean Development Mechanism (CDM) is a scheme created by the Kyoto Protocol that awards carbon offset credits to investors in projects located in developing countries that reduce net greenhouse gas emissions in the country concerned. Financial and operating data on all registered projects are available at http://cdm.unfccc.int/.

international prices develop as forecast by the IEA, wind will be cheaper than coal, at the margin, by about 2019. By that time, power from a new plant burning imported coal will be the most expensive option of those considered in this research, other than solar PV. In Southern India, where wind conditions are favorable, wind power was already cheaper than power from imported coal in 2011. This significant change in the realities underpinning Indian energy policy provides a strong argument for a maximum renewables (or nuclear) energy policy.

In section 2 of this paper I describe the methodology I use for the analysis; section 3 lays out the results and section 4 provides a discussion of factors highlighted in the results analysis, with some overall conclusions.

8.2: METHODOLOGY: RENEWABLE GENERATION PROJECTS

8.2.1: Analysis of costs

The basis of my methodology is comparison between the costs of electricity based on renewable generation technologies (wind, hydro and solar PV) and a baseline coal fired plant. My estimates of generation costs for wind and small hydro are taken from an earlier paper in which I estimate generation costs by project for samples of wind and small hydro projects (and two solar PV projects), and use learning rate analysis to project future costs for these technologies (Partridge, 2012b). In this section I summarize the approach - for a more detailed explanation, please see the earlier paper.

Generation cost is estimated using the identity:

$$Generation\ Cost\ per\ MWh = operating\ cost + capital\ cost + intermittency\ cost$$

Data on operating and capital costs are obtained from the database of CDM projects maintained by the UNFCCC (http://cdm.unfccc.int/) which contains a PDD (project design document) for each registered project. Capital cost in this case means initial investment cost annualized using the annual capital charge (ACC) methodology - see

(Merrett and Sykes, 1973). A key input to the ACC calculation is the weighted average cost of capital (WACC) appropriate to the project - my assumptions concerning WACC are described in section 8.3.3. Intermittency costs arise because the output of a wind turbine fluctuates due to the intermittency of the wind resource,[114] imposing costs on the grid operator due mainly to the need for additional conventional generation as backup. An analysis of intermittency costs would require a complex simulation exercise for the whole Indian grid, however a review of fifteen European and US studies (Holttinen et al., 2009) indicates that a conservative estimate of the added cost where wind contributes up to 5% of total supply to a grid would be $1.50 per MWh.[115] Wind contributed only 2% of Indian electricity generation in 2009 (IEA, 2011).

Small hydro plants often operate on a seasonal basis depending on rainfall, but during the period of operation output is reasonably predictable. I spread costs and generation by seasonal plants over the year, but assume zero intermittency costs.

8.2.2: Learning rate analysis

The observation that manufacturing costs fall as experience of a technology accumulates was reported by (Wright, 1936). It has become the basis for learning rate (or experience curve) analysis which, as used today, models the relationship between manufacturing cost and cumulative volume manufactured. Learning curves based on such models are widely used for cost forecasting: according to Alberth and Hope (2007), "(learning curve analysis) in log format, is a very useful first order approximation (of future costs) with the distribution of the forecast error being both symmetrical and unbiased with a mean value that is statistically not different from zero". Alberth and

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[114] The same is true of solar. In the limited analysis we have been able to do of solar PV projects in India we assume the same level of intermittency costs as for wind projects.

[115] Many of these studies include estimates of the cost impact at various levels of wind contribution to total generation. Extrapolating back to 5%, the median added cost is about $1.3, so $1.5 is conservative.

Hope did point out that the translation of log into normal format forecasts introduces a bias towards overestimation of cost reductions, but that this is not significant for medium term forecasting. (Alberth and Hope, 2007). They suggested that medium term means about twelve years, in the context of an analysis of GHG abatement technologies.

I apply learning rate analysis[116] to renewable generation technologies (wind and small scale hydro) in India and use the results obtained to forecast future generation costs out to 2020. For wind generation, a regression analysis with log(generation cost) as the dependent variable shows that project size has no significant effect on generation cost. The final model used for cost forecasting is outlined in table 8.1.

Table 8.1: Generation Cost Analysis – Wind

Dependent variable:	log of generation cost (INR(2012) per MWh)
Number of observations:	240
R^2:	.4375
Adjusted R^2:	.4328

	Coef.	Std. Err.	t	P>|t|	95% conf. interval	
Log_cum	-0.2065	0.0280	-7.38	0	-0.2616	-0.1514
Is_south	-0.1723	0.0146	-11.81	0	-0.2013	-0.1438
Constant	10.1415	0.2611	38.84	0	9.6271	10.6559

Notes: Log_cum is the log of cumulative installed capacity in MW;

Is_south is a dummy variable (=1 if project is located in Southern grid region)

The negative coefficient on the is_south variable in table 8.1 indicates that costs are lower in the South; the coefficient on cumulative capacity[117] indicates a 13.3% learning rate – i.e. generation cost (in real terms) reduces by 13.3% for a doubling in cumulative

[116] This section summarizes an earlier paper by the same author (Partridge, 2012b).

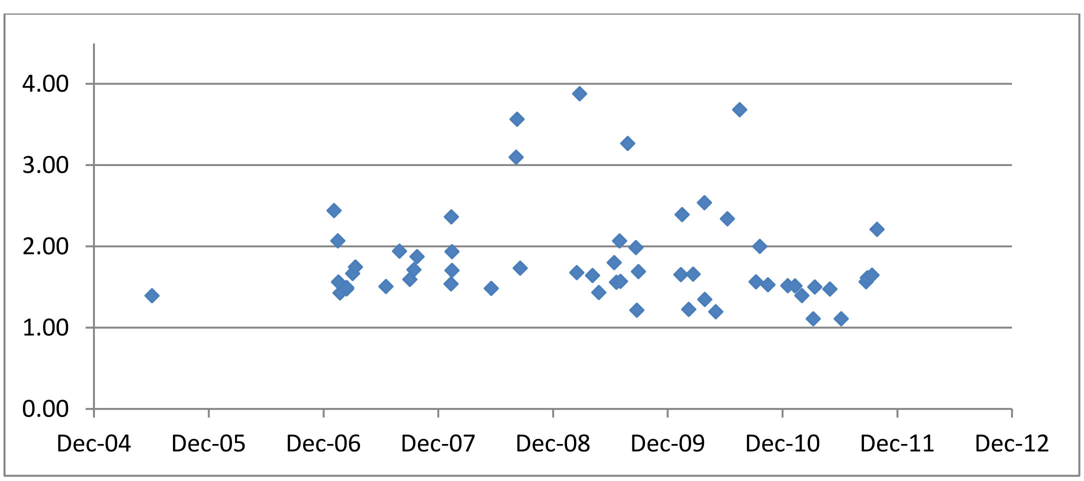
[117] Based on data on cumulative wind capacity installed in India obtained from the Ministry of New and Renewable Energy (http://www.mnre.gov.in/).

capacity installed (95% confidence interval 10.0%-16.6%). Separate model runs for the first half and second half of the period show no indication of flattening in the later years – in fact, the curve appears to get steeper, though the short time periods for these two runs mean that the confidence intervals are wide. The lack of any scale effect is surprising - other studies of wind generation commonly find economies of scale (Wiser and Bolinger, 2011) – however it may be due to a peculiarity of the Indian wind industry: it is common in India for a wind turbine manufacturer to develop a wind farm on behalf of a number of investors, each of whom takes ownership of a small number of turbines. Because of the way that the data are presented in the project PDDs I treat each sub-project as a separate CDM project: this would mean that small projects in the sample may have access to economies of scale typical of a larger wind farm.

Additional regressions (not shown) to further explore regional differences show that capital costs do not vary significantly by region, but plant load factor (electricity generated as a percentage of the maximum theoretically possible for the turbine) is higher in the South and shows no trend over time.

For small hydro, a scatter chart of generation costs against time (chart 8.1) shows a number of outliers – consistent with a high degree of forecasting uncertainty.

Chart 8.1: Generation cost – hydro (INR(2012)/kWh)



The final model for hydro generation shows no significant learning effect (table 8.2). There is a small scale effect with lower generation cost in the North of India compared to other regions. The relatively low R^2 and the fact that the two independent variables are significant only at the 10% level indicate that my hydro forecasts are less reliable than my wind forecasts – as might be expected from the many outliers in chart 8.1.

Table 8.2: Generation cost analysis – hydro

Dependent variable:	log of generation cost (INR(2012) per MWh)
Number of observations:	57
R2:	.1099
Adjusted R2:	.0769

	Coef.	Std. Err.	t	P>|t|	95% conf. interval	
Log_cap	-0.0529	0.0286	-1.85	0.07	-0.1103	0.0045
Is_north	-0.1303	0.0727	-1.79	0.079	-0.2761	0.0155
Constant	7.6748	0.0877	87.5	0	7.4990	7.8507

Notes: Log_cap is the log of project capacity in MW;

Is_north is a dummy variable (=1 if project is located in Northern grid region)

As of March 2012, two grid-connected solar PV projects (both of 5 MW capacity) had been registered as CDM projects in India. Their generation costs, based on the same methodology used for wind and hydro, are INR 11.2 and INR 14.4 per kWh (currency of 2012). The cost of solar power is falling rapidly: a recent McKinsey and Co report (Aanesen et al., 2012) projects a LCOE for large solar PV installations of INR 5.0 per kWh in 2020 (2012 currency). In section 8.4.3 I discuss the possibility that solar could make significant inroads into the share taken by coal in the future.

8.2.3: The project sample - statistical considerations

The sample of renewable generation projects used for this research comprises 100% of wind, hydro and solar projects that were registered as CDM projects as of 12/31/2011. In most cases the PDD contains sufficient data to enable the capital and operating elements of generation cost to be calculated. However for some projects the data in the PDD are insufficient : this is the case for 17 of the 60 wind projects that requested registration in 2005-2007 but only two out of 199 projects from 2008-2011. The situation with hydro projects is similar: 27 out of 41 2005-2007 projects could not be used but only three out of 46 of the 2008-2011 projects. There is a possibility that the higher incidence of missing data for older projects could bias my estimates.

Where investment cost data are given (18 of the 30 non-usable hydro projects and 10 of the 19 wind projects), statistical tests for potential bias show that it is not possible to reject the null hypothesis that the populations of usable projects and missing data projects have the same mean. In all cases, the PDDs show project capacity in MW. Comparing usable projects and missing data projects on the basis of project size, I find that, for wind projects, there is again no indication that the samples have different means. I conclude that, for wind generation, the preponderance of older projects among those with missing data does not bias my results. However for hydro, missing data projects are on average smaller than usable ones. As my generation cost model shows a scale effect, it is likely that my average estimated generation cost for earlier hydro projects is underestimated.

I re-run my learning rate analysis for all hydro projects with the generation costs of the missing data projects determined by my regression model. There is an element of circular reasoning, but the test provides at least a strong indication that the key conclusion of my learning rate analysis – that cumulative capacity installed has no significant effect on generation cost – remains unchanged. For more details of the tests employed, please refer to the earlier paper.

8.3: METHODOLOGY: COAL FIRED PROJECTS

8.3.1: Costs and efficiency

I compare the costs of renewable generation technologies with those of the baseline plant, defined as the marginal plant (the next to be built) based on conventional technology. In India the marginal conventional plant is coal fired (in section 8.4.3 I consider the possibility that this might change at some time in the future).

Ten years ago most generation plants being built in India were 500MW subcritical units designed by Bharat Heavy Electricals Limited (BHEL), based on indigenous technology and optimized to burn domestic coal. Today, the country is switching to supercritical boiler technology and imports of coal are growing rapidly. The government's "Ultra Mega Power Project" (UMPP) program has effectively delegated design decisions to Independent power producers. Four UMPPs – all supercritical - are under construction, with two at the bidding stage and several others planned. At least one supercritical plant outside the UMPP program is already operating. I compare the costs of renewable generation both to the former subcritical standard and to a modern supercritical unit. [118]

The impact of increasing imports of coal on Indian generation costs is complex: many power stations are using a blend of imported and domestic fuel – this is the case even for plants at inland locations which must add rail transport costs to the already high cost of imported fuel. To simplify this situation, I assume that all plants use either 100% domestic or 100% imported coal. I calculate generation costs for all locations based on a typical grade of domestic coal: for coastal locations only, I also consider a typical grade of imported coal.

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[118] A supercritical boiler generates steam at a higher temperature and pressure than the previously standard subcritical units: this enables it to operate at a higher level of efficiency, but the high operating temperature requires the use of sophisticated materials in its construction, with associated manufacturing difficulties.

Estimates of baseline generation costs depend crucially on assumptions on the thermal efficiency of coal fired plants, and on their capital and operating costs. Assumptions on plant efficiency, capital and non-fuel operating costs are taken primarily from project PDDs. Many of these use the BHEL 500MW unit as the baseline: some also provide data on supercritical plants as several such plants in India have been put forward for CDM registration on the grounds that their higher thermal efficiency enables them to cut CO_2 emissions per unit of electricity generated compared to a subcritical plant. Data are obtained also from sources such as reports of regulatory hearings and some reports (MIT, 2007; Mott McDonald, 2006). My understanding of the various sources was much helped by contacts with engineers at the Indian Central Electricity Authority (CEA).

Construction cost estimates for subcritical and supercritical plants are shown in table 8.3: for comparison the table shows estimates from reports by MIT (*The Future of Coal* (MIT, 2007)), and by Mott McDonald (consulting engineers) (Mott McDonald, 2006).

Table 8.3: Estimates of Construction Costs

US$ per kW	Subcritical	Supercritical	Difference (%)
Assumed in this report	652	920	41%
From (MIT, 2007)	1280	1330	4%
From (Mott McDonald, 2006)	1224	1293	6%

The three sets of estimates in table 8.3 apply to different countries in different years,[119] over a period when plant costs fluctuated as a boom in global construction was followed by financial crisis. However in my view the sources are probably internally consistent: the cost premium for a supercritical plant over the less sophisticated subcritical plant

[119] The Mott McDonald report was published in 2006: its construction cost estimates assume all imported components erected on site using Indian labor; cost estimates in the MIT report (published in 2007) are for US projects; our construction cost data are taken mainly from descriptions (PDDs) of Indian CDM projects that applied for registration during 2008-2011.

should be the same in each case. In fact, it is higher in India - in my view because the subcritical plant uses Indian technology and Indian firms have lengthy experience of building plants to this design; the supercritical design is new to India and uses foreign technology. If this is the correct explanation, the effect is likely to be temporary.

A direct parallel is found in a study of the cost of reducing CO_2 emissions by substitution of natural gas combined cycle (NGCC)[120] generation for coal in India and the US (Sathaye and Phadke, 2006), which found a higher marginal abatement cost in India. Construction costs of NGCCs were found to be higher in India: the authors speculated that, as the technology matures, the cost differential between India and the US would narrow. Their findings parallel the results of this study: the reason for the results obtained are that plant costs in India depend on the extent to which the technology concerned is owned (in both the literal and figurative senses) by Indian firms. Both studies demonstrate how technology transfer issues interact with energy policy.

8.3.2: Cost of coal

Fuel cost estimates for all locations are based on the specifications of coal sampled at Dadri power station by a team from Ohio State University.[121] The specifications are typical of grades supplied to thermal power stations in India, with high ash content (38.22%), low sulfur (0.5%) and energy content (Gross Calorific Value, or GCV) of 3692 kcal/kg. The Indian Ministry of Environment and Forests requires that coal with ash content no greater than 34% is used in environmentally sensitive areas or where the rail delivery distance is over 1000 km. I assume that this is achieved by washing raw coal to reduce its ash content. Cost of washing is estimated based on data from CEA engineers.

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[120] An NGCC plant is complex but achieves much higher levels of thermal efficiency than a coal-fired plant.

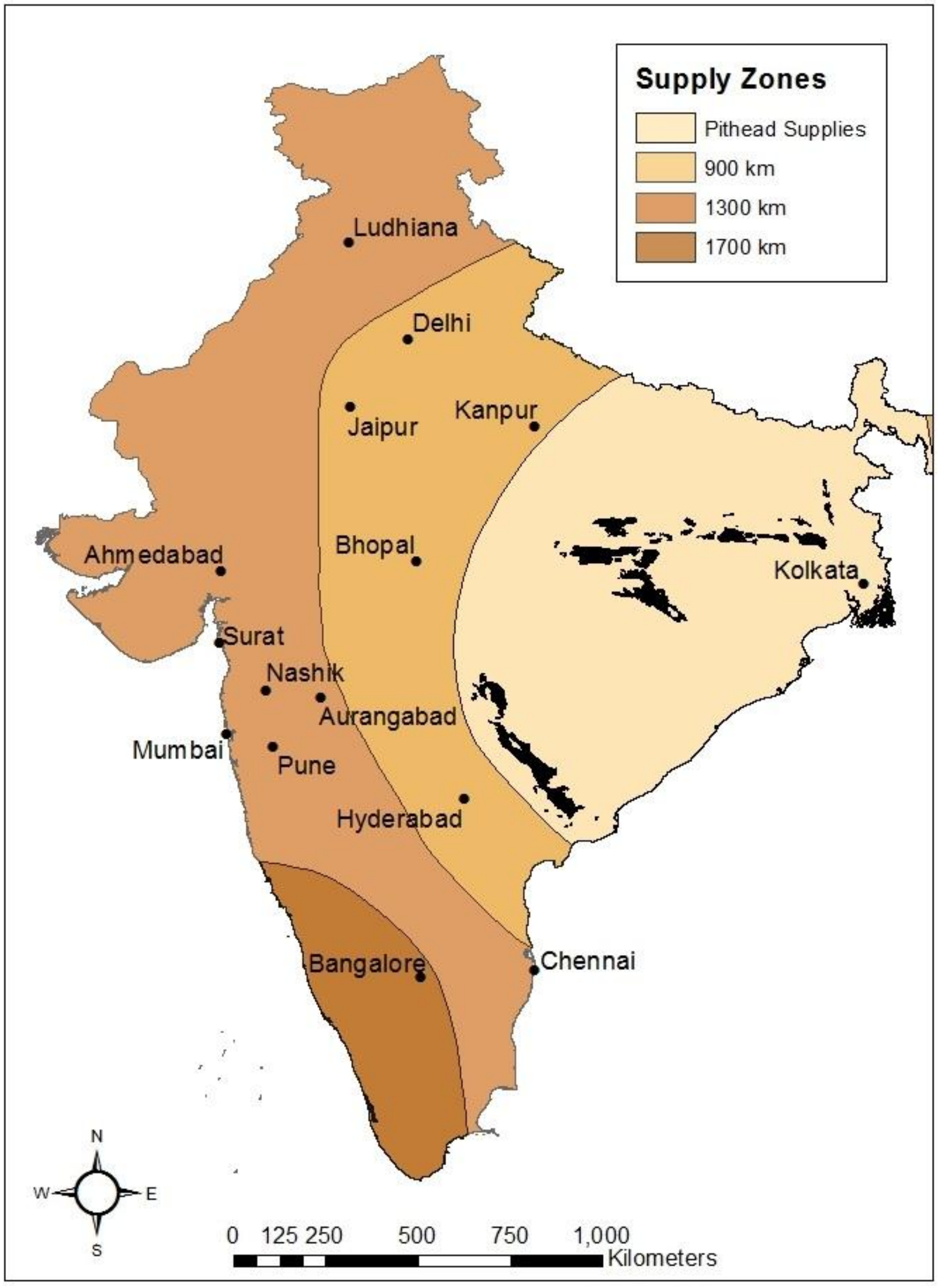
[121] See http://www.osc.edu/research/archive/pcrm/emissions/coal.shtml.

Pithead prices of domestic coal are published by Coal India Limited (CIL). I add indirect taxes that have the characteristics of a cost: this includes mineral royalties, as they are payments for the use of a resource that belongs to the government (Otto et al., 2006) and some charges for use of forest land. I do not include other indirect taxes such as value added tax (VAT), which has no impact on the cost of electricity *to India*.

The cost of rail freight means that distance between mine and power plant accounts for large regional differences in generation cost. I estimate freight costs based on likely supply patterns for new plants determined by analysis of CIL output forecasts to identify mines that can significantly increase production. Delivery costs are estimated based on distances from these mines to plant locations and on published freight rates. The main coal mining regions are located in Eastern and Central India. The hypothetical marginal plant in this area is located at the pithead. Delhi and industrial areas in Northern India are on average about 900km by rail from mines able to increase output. Most other industrial centers are located roughly 1,300km from incremental supplies of domestic coal, including coastal locations in the West (in Maharashtra and Gujarat) and in the South East. Incremental coal supplies to Bangalore and the South West of India must travel more than 1,700km by rail. An outline map of the supply regions is provided (Map 1). Assam and the North east are excluded from the analysis.

Most of India's coal imports come from Indonesia. Until recently, firms developing investment proposals for large power stations in India fuelled by imported coal would base their cost estimates on quoted prices for very low grade Indonesian coal, taking advantage of the low price per unit of energy content for these grades. However, in September 2011 the Indonesian government acted to require parity of export prices per unit of energy for all grades. Sourcing of future imports to India is now highly uncertain (see articles in The Economic Times (Mumbai) of October 3 2011, and Reuters of April 4, 2012). In the absence of clear information, I base my calculations on the specifications and official price of benchmark grade Indonesian coal with a GCV of 6322 kcal/kg.

Map 8.1: Supply zones and principal coalfields

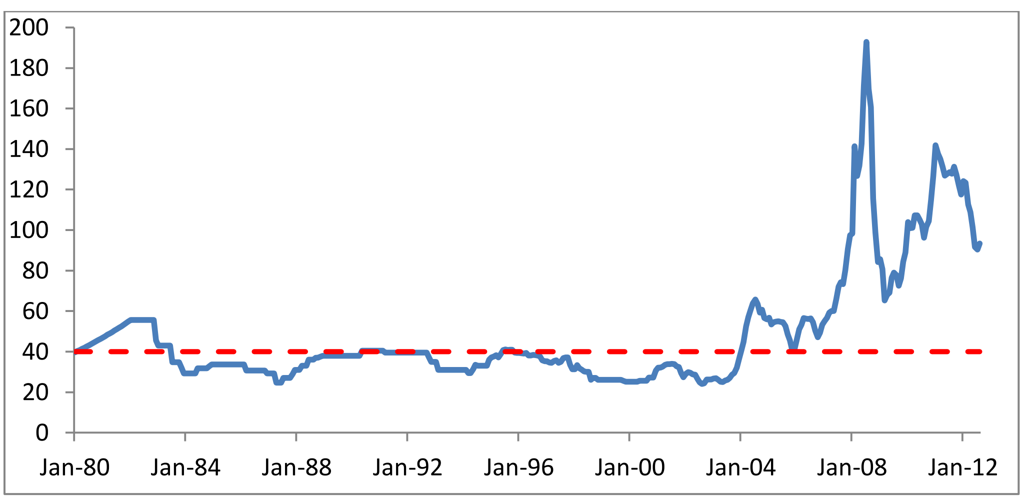


Source of coalfield Locational data: (Trippi and Tewalt, 2011)

Generation cost estimates presented here are levelized cost of electricity (LCOE) – i.e. based on forecast costs over the roughly forty year lifetime of a new plant discounted back to the base year. Due to the volatility of international coal prices, the assumption used in many LCOE calculations of constant real terms prices is inappropriate. I define scenarios that I believe provide upper and lower bounds for prices. In the low price scenario coal behaves as a quintessential commodity: it is traded in a competitive market; global reserves are large and OPEC type price controls are not feasible due to the diversity of current and potential producer countries. In the long term prices should fluctuate around the long run marginal cost of new supplies, or LRMC (which may vary over time (Pindyck, 1999). Mott McDonald (UK consulting engineers) forecast prices for a report on Indian power projects by assuming an LRMC for Pacific basin exporting countries of US$40 per ton[122] (Mott McDonald, 2006). During the period 1980 to 2004 international prices approached this level on several occasions then fell back (chart 8.2). This commodity type price behavior lends credibility to the Mott McDonald approach.

Chart 8.2: Australian Coal Price Index

Price index for Australian steam coal;[123] 6667 kcal/kg; fob Port Kembla; US$/t.



Source: IMF

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[122] Metric tons are used throughout this paper.

[123] The chart shows the Australian price index as it has been calculated on a consistent basis over more than thirty years. The Indonesian benchmark price has been quoted only since 2009.

Since early 2004, prices have risen far above $40, driven by booming demand from Asia. In 2008 production costs in exporting nations rose by about $10 per ton, driven by higher prices for diesel fuel, labor, steel and other inputs. By 2010, costs had risen to an average for the main producing countries of about $56 per ton (IEA, 2011). These are short run marginal costs, but it is likely that the proposed or recently opened mines in such areas as Mongolia and more remote parts of Australia have pushed LRMC up to about $50 per ton (IEA, 2010, quoting data from Marston and IHS Global Insight). For my lower bound forecast I assume that the Indonesian benchmark falls to $50 per ton (2010 Dollars) fob loading port in 2020, and then remains constant in real terms.

For the upper bound coal price scenario I use the IEA's forecasts from its annual World Energy Outlook – specifically its New Policies Scenario, which is based on "cautious" implementation of already announced measures to combat climate change (IEA, 2011). My "IEA scenario" is the New Policies Scenario adjusted to reflect Indonesian prices. My coal price forecasts for a location on the West coast of India are shown in table 8.4.

Table 8.4: Delivered Cost of Coal in 2020 – India West Coast ($(2012)/t)

	Domestic	Imported	
		LRMC	IEA
Pithead price	793	2,861	5,393
Freight & Handling	1,384	1,102	1,102
Royalty etc	225	25	25
Delivered Cost	2,402	3,989	6,520
GCV (kcal/kg)	3692	6322	6322
Delivered Cost (US$/GJ)	2.63	2.77	4.52

8.3.3: Return on capital

A significant element of the cost of electricity is the return required by investors in generation assets, including interest on debt financing and the after tax return on equity

(RoE). The required after tax RoE, appropriately adjusted for risk, can in principle be estimated using the capital asset pricing model (CAPM). The standard formulation is:

$$r_i = r_f + \beta_i * (r_m - r_f) \quad (1)$$

where r_i is the expected return on an investment *i*, r_f is the expected return on a risk free investment (the risk-free rate) and r_m is the expected return on the whole market. β_i is the Beta value for the investment - a measure of risk relative to the market.

The CAPM estimate of the expected post-tax return on equity (RoE) for thermal generation in India is 15.7%, based on a risk-free rate equal to the rate on Indian government ten year bonds (8.654% as of April 27 2012); a market risk premium of 8.5% (the average reported by 28 Indian academics and practitioners to a survey made by a team from the University of Navarre (Fernandez et al., 2011)); and a Beta for the Indian power sector of 0.83, obtained from an online dataset maintained by Professor Damodaran of the Stern Business School at New York University.[124]

In principle, the RoE required by investors in renewable energy can also be estimated using the CAPM. a study by Donovan and Nuñez of the cost of capital for renewable energy projects in developing countries has an estimated Beta of 1.45 for Indian renewable energy projects (Donovan and Nunez, 2012). Using this figure, the CAPM gives a post-tax RoE for the Indian renewable energy sector of 21%.

The portfolio used by Donovan and Nuñez to compute Beta includes large companies engaged primarily in thermal generation, manufacturers of renewable generation equipment and a few companies – typically only recently quoted – that make most of their income from renewable generation. The Indian Central Electricity Regulatory Commission (CERC) does not use the CAPM for setting tariffs for renewable generation -

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[124] See http://pages.stern.nyu.edu/~adamodar/New_Home_Page/data.html. Version used was updated in January 2012; accessed April 30, 2012.

it believes that the small number of renewable generation companies quoted on the Indian market means that the data are unreliable.[125] The makeup of the portfolio used by Donovan and Nuñez tends to confirm this opinion. I use the CERC target RoE for renewable generation projects, which is 15.6% post-tax, taking account of a ten year tax holiday available to all renewable generation projects - in practice they pay a minimum alternative tax (MAT) rather than the full corporate rate (which is clearly sufficient to attract investment – according to an analysis by Bloomberg New Energy Finance, India invested $10.3bn in clean energy projects in 2011.[126])

8.3.4: Generation costs – domestic and imported coal

Table 8.5 shows estimated generation costs for 2009-2012 for each of my defined supply zones. The cost estimate for imported coal applies to any coastal location. The table shows that, for all regions and all years, a new plant fuelled by domestic coal produces electricity more cheaply than a new plant of the same type using imported coal - even in Southwest India, where the cost of domestic coal includes rail freight over 1,700km. The comparison of subcritical with supercritical technology is not so clear-cut: in general, the higher efficiency of the supercritical plant gives it a cost advantage where coal prices are high but with low coal costs – as in the pithead supply region – subcritical is cheaper. The difference is nowhere more than a few percent. In most of the world the more efficient supercritical plant would have a clear cost advantage (MIT, 2007). In section 8.3.1 I suggest that this apparently anomalous situation may reflect the fact that the subcritical plant uses indigenous technology: Indian firms have built large numbers of these plants, enabling them to cut costs due to a learning curve effect. In time, they will build up a similar level of experience with supercritical technology.

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125 http://cercind.gov.in/2009/February09/SOR-regulations-on-T&C-of-tariff-05022009.pdf (accessed April 27, 2012).

126 http://bnef.com/PressReleases/view/186 (accessed August 8 2012).

Table 8.5: Generation costs - coal (INR/kWh)

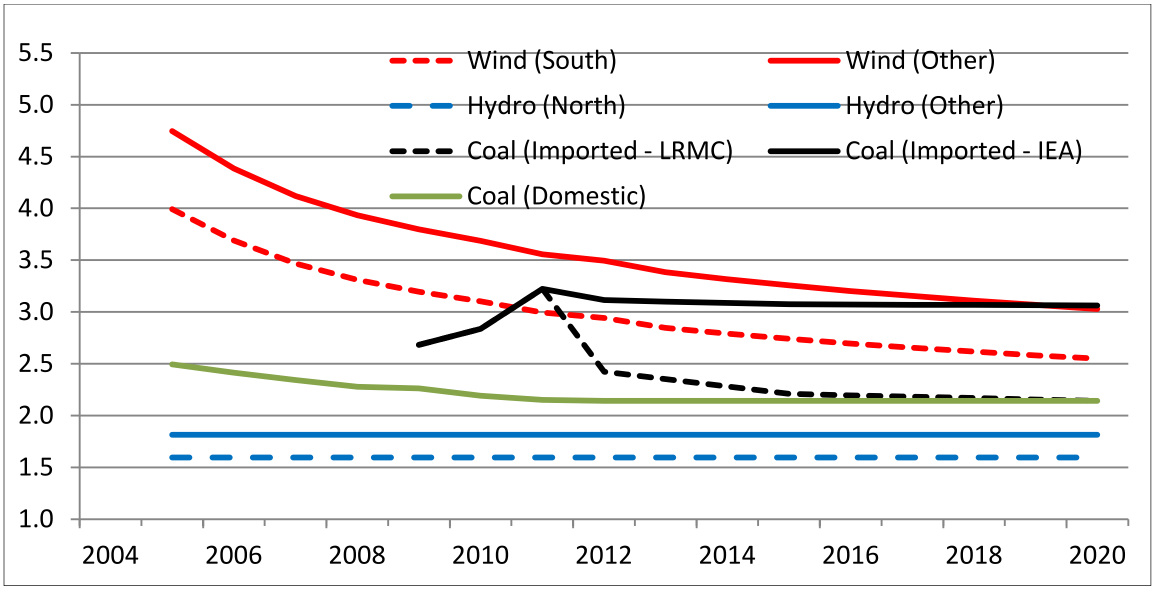
Plant Type		Subcritical	Supercritical
Domestic Coal (Pithead Supply)	2009	0.93	1.02
	2010	1.04	1.15
	2011	1.14	1.26
	2012	1.13	1.26
Domestic Coal @ 900km (Delhi)	2009	1.54	1.56
	2010	1.66	1.70
	2011	1.79	1.83
	2012	1.86	1.91
Domestic Coal @ 1,300km (Southeast, West and Punjab)	2009	1.76	1.76
	2010	1.88	1.89
	2011	2.02	2.03
	2012	2.13	2.14
Domestic Coal @ 1,700km (Bangalore and Southwest)	2009	1.96	1.94
	2010	2.09	2.07
	2011	2.23	2.22
	2012	2.40	2.39
Imported Coal (Coastal Location)	2009	2.08	2.07
	2010	2.43	2.41
	2011	3.02	2.96
	2012	3.26	3.19

8.4: Policy issues and conclusions

8.4.1: Generation costs – summary and forecasts

I now have models for generation costs for both renewable and coal-fired plants and can plot the predictions for all technologies analyzed on one chart – see chart 8.3.

Chart 8.3: Generation cost comparisons - INR(2012))/kWh



Some methodological points are:

- Costs for wind and hydro are predictions from the learning curve models discussed above, based on figures for capacity in 2020 from the report Low Carbon Strategies for Inclusive Growth (Planning Commission, 2011)). For hydro, where the regression analysis shows a small scale effect and no learning, the projections are based on a 25MW unit with a constant generation cost in real terms, differentiated by region.

- For coal, projections through 2011 are for a subcritical plant: from 2012 the assumed marginal plant is a supercritical unit, with capital cost falling due to learning from 2015.[127] Cost for domestic coal is for coastal regions in the South and West.

- Prices for domestic coal are assumed to be constant in real terms after 2012. Pithead coal prices in India are much lower than fob prices in the major exporting countries. Table 8.6 shows delivered prices in terms of cost per unit of energy, to

[127] Based on a 15% learning rate. Cumulative capacity installed in 2015 based on company press releases and cumulative capacity in 2020 from (Planning Commission, 2011).

remove distortion due to quality differentials (2012 price is January-August average). Currently, imported coal is significantly more expensive, though in the LRMC scenario prices of domestic and imported coal converge.

Table 8.6: Coal cost delivered to power station ($/GJ)[a]

	2010	2011	2012
Pithead	1.10	1.19	0.93
Delhi	2.36	2.46	2.18
Southeast, West & Punjab	2.80	2.91	2.63
Southwest	3.21	3.33	3.09
Imported[b]	4.10	5.12	4.78

Notes: (a) In current Dollars including royalty, freight, handling charges etc.

(b) Indonesian benchmark grade delivered to a power station located near the unloading port: freight cost assumed the same to all Indian ports.

In terms of potential impact on policy, the most important result presented here is the prediction that in the IEA scenario the costs of wind generation and of the marginal coal fired plant will converge and in 2019 will cross. Thereafter, coal in a new plant will be the most expensive of the technologies considered in this research other than solar – as it already is in the South. This result follows directly from a switch to imported coal as India's marginal fuel due to the failure of Coal India Limited to significantly increase output of domestic coal. The significance of this result for India's energy planners can hardly be overestimated.

8.4.2: Sensitivity analysis – macroeconomic events and generation cost projections

It is worth considering what changes in assumptions might invalidate my conclusion of a wind/coal generation cost crossover in about 2019 in the IEA coal price scenario – in other words, in what circumstances would the world slip into the LRMC scenario? The LRMC scenario is based on the economics of coal production, not macroeconomics, but it would clearly become more likely if slower growth in the Asian "tiger" economies triggered a significant reduction in international coal demand. In a world where growth in these economies remained slow in the long term, the predicted wind/coal cost crossover might be postponed indefinitely.

There is some uncertainty also about cost projections, which are based on data from project PDDs. The data are forecasts rather than actual figures – a PDD is typically prepared before project construction starts. It is possible that PDD cost projections are inaccurate and may be systematically biased.[128] In the case of wind power, estimates of generation cost depend on three parameters – capital cost, variable operating cost and plant load factor (PLF) – defined as the total quantity of electricity produced expressed as a percentage of what could theoretically be produced if the unit worked at its design output for 100% of the time. Of these three, construction cost estimates for wind farms are probably accurate - Indian engineers are experienced with the technology and designs are standardized; the influence of variable costs is limited - wind generation is characterized by very low levels of variable costs (Wiser and Bolinger, 2012); PLF, however, is difficult to estimate with any degree of accuracy. It depends to a significant extent on the expected average wind strength over the course of a typical year: in a developing country, this is unlikely to be known with any degree of certainty.

I consider how my projection of wind/coal cost crossover in 2019 would change if actual PLFs were 10% and 15% below PDD forecasts. Assuming that India continues to build wind farms at the rate seen in recent years, and that the relationship between cumulative capacity and generation costs does not change, the crossover year would be 2029 for a 10% shortfall and 2037 for a 15% shortfall. On the other hand, if the PLFs

[128] As the purpose of a PDD is to prove that the project is additional – i.e. that it is not viable without subsidy – any systematic bias might be towards an underestimate of profitability.

implied in the project PDDs are 10% too low, crossover would occur in 2013. Clearly, any systematic bias in PLF projections would have a significant impact.

PLF depends to some extent on the design of the unit – for example, mounting a wind turbine on a higher tower increases its PLF compared to the same turbine on a lower tower as wind tends to be stronger at greater heights (Wiser and Bolinger, 2012). However, by far the most important influence on the PLF of a wind plant is location. Some places simply get more wind than others – see tables 8.7a and 8.7b.

Table 8.7a: Capacity weighted average PLFs - US by region (2004-2010)

Region	Average PLF
East	24.9%
Northwest	28.0%
New England	29.4%
Great Lakes	30.3%
Texas	31.9%
Mountain	34.6%
California	35.8%
Heartland	37.0%
Total US	33.6%

Source: (Wiser and Bolinger, 2012)

Table 8.7b: Average PLFs - India (2006-2011)

Region	Average PLF
Southern India	26.6%
Rest of India	22.5%

It appears that PLFs in Southern India – the region with the best wind resource – are low by US standards, while PLFs in the rest of India are very low – below average levels in even the least favored regions of the US. There is also a high level of variation within a region: PLFs in South India ranged between 16.4% and 37.1% (n = 120). Despite the fact that the performance of the average project is poor, the best are comparable to those in the US. There is a need for further research on the reasons for this wide spread of PLFs, and on the relationship between these forecast PLFs and those actually achieved.

My analysis assumes a constant learning rate - however wind generation costs in the US departed from a learning curve trajectory in about 2004 as the plant and equipment market overheated. There is no sign of this happening in India, but estimated crossover dates of 2029 and 2037 presented as sensitivities should not be seen as point estimates, while even the base case estimate of crossover in 2019 is risky.

For coal fired plants, generation cost projections depend crucially on the future course of coal prices – in particular international prices, as imported coal is India's marginal energy resource in the future. I deal with uncertainty by basing cost projections on two price scenarios for imports. There is also uncertainty over capital costs of supercritical plants in Indian conditions. In section 8.3.1 I show that the value used in my estimates is significantly higher than would be expected based on a comparison of differentials between subcritical and supercritical costs in other countries. Project PDDs suggest a 41% differential between the total investment cost per MW of subcritical and supercritical plants, however independent sources in the UK and the US show differentials of the order of 5%.

I suggest in section 8.3.1 that the discrepancy is due to Indian engineers' lack of familiarity with supercritical technology, however another possibility is that my cost estimate for supercritical is too high – it is based on a small sample of PDDs and the converse (subcritical cost estimate too low) is less likely as large numbers of subcritical units have been built in India and construction cost data are public knowledge. A sensitivity analysis shows that, if my construction cost estimate for supercritical units is replaced by a value 5% higher than the estimate for subcritical plants, my model would predict wind/coal cost crossover in 2022 rather than the base case prediction of crossover in 2019.

8.4.3: Alternative baseline scenarios

An implicit assumption of the analysis described is that the marginal source of electricity for India for the next several decades at least will be coal. Is this a foregone conclusion? Certainly, all recent assessments by the Indian government of long term energy policy have accepted it as a fact.

Of technologies that are fairly well developed, only two might possibly usurp the role of coal in Indian power generation during the next twenty years. One is unconventional gas – particularly shale gas, which has dramatically changed the energy picture in the USA. The other possibility is that distributed generation based on solar and biomass could absorb much of the expected growth in electricity demand, allowing the grid-connected generation system to consolidate and focus on efficiency.

Estimates of Indian reserves of unconventional gas look more like guesses than scientific assessments. Figures given by Schlumberger – the multinational oilfield services firm – are probably better than most: Schlumberger has the distinction of having drilled and discovered gas in a shale deposit in India. It has estimated that shale gas reserves in India (gas in place) fall within the range of 300 tcf-2,100 tcf.[129] Assuming 15% is recoverable, economic reserves might lie between 45 tcf and 315 tcf.

According to the BP Review of World Energy, India's proven reserves of conventional gas at the end of 2011 amounted to 43.8 tcf, with annual production of 1.6 tcf and consumption of 2.2 tcf – the balance being accounted for by imports. At the low end of Schlumberger's range of estimates economically recoverable reserves would double -

[129] Indian press reports quote an unnamed Schlumberger executive to this effect, but the company does not seem to have issued a press release or other documentation of the figures.

useful, but not a game-changer. At the high end, reserves would increase by a factor of eight, providing over two hundred years of production at historic rates. It would be possible to envisage a situation in which most new generation capacity would be gas fired – the situation in the US for the past several years.

However, even if the reserves are there, they have to be developed. Two Schlumberger consultants, writing in DEW Journal (Drilling and Exploration World) argued that India may find it extremely difficult to replicate the success of shale gas development in the US (Verma and Shanthamurthy, 2010). They see problems in three key areas:

- In the US, mineral rights belong to the landowner. Exploration companies can assemble exploration rights and surface access over large areas. It helps that many areas that are prospective for shale gas are sparsely populated and landholdings are large; however even in more populated regions such as New York State, the alignment of interests between landowner and exploration company smoothes over problems. In India, mineral rights belong to the government, the country is relatively heavily populated, landholdings are often small and landowners' rights are jealously guarded.

- The US benefits from a large and competitive oil and gas services industry: in 2008, 1,400 – 1,500 rigs drilled about 35,000 natural gas wells; in India, fewer than 100 land rigs drilled less than 650 wells. The US has a large pool of experienced field personnel and geoscientists, and competition among service companies spurs innovation and drives down costs. Furthermore, a long history of exploration has built archives of geological data that simplify the task of exploration (Verma and Shanthamurthy, 2010). India has none of these advantages.

- Finally, the shale gas revolution in the US has been helped by a pre-existing pipeline infrastructure and the availability of highly liquid markets for the gas produced – an active market in gas futures means that day to day drilling activities can be partly financed by futures sales. India's energy markets are mostly tightly controlled and its infrastructure is undeveloped.

On balance, it seems unlikely that shale gas will revolutionize India's energy scene. Even if the reserves exist, I would anticipate a long slow build-up of production, driven by state-owned industries and a few large multinationals. Possibly the best that can be hoped for would be more construction of gas fired plants aimed at easing the country's lack of peaking capacity rather than baseload.

Distributed generation is widely regarded as the wave of the future: a cynic might add that it always will be. On the positive side, India's near 300 million people with no access to the electricity grid create a strong incentive to make distributed generation work and the government puts a high priority on rural electrification. The main technologies involved are fairly simple and there is more scope for individual initiative and competition than in the gas business, with its underlying natural monopoly.

There are also negatives: there are some very large vested interests behind extension of the grid, which would maintain the key roles of the state owned companies and the huge private sector concerns that have invested in power generation. The government has wisely prioritized distributed generation for rural areas, but will have a hard time maintaining focus when the problems in the grid connected sector are so pressing and the lobbying power of its protagonists so overwhelming.

Nevertheless, it seems likely that distributed generation as a way to meet the energy needs of rural areas will grow rapidly. It will not supplant coal as the main baseload power source: what it might do would be to enable India to grow its economy while expanding energy supply to all sectors of the population. If this freed up the grid connected sector to put less emphasis on a frenetic growth rate and focus more on infrastructure, meeting peak load requirements and integration of renewables, the economy would benefit. The need to maximize investment in renewables and cut the use of coal would still be a key driver of India's energy policy, leaving the analysis presented in this paper still valid.

8.4.4: Conclusions

Imported coal is now the marginal energy source for India: given the volatility of internationally traded coal prices, this significantly increases the level of economic risks to which the country is exposed (and complicates the task of economic forecasting). My analysis draws on two forecasts of international coal prices: in the high price case, power from a new coal fired plant burning imported coal becomes the most expensive option of those considered, other than solar PV, by about 2019. This is the most significant change from the current situation identified in this paper. On the other hand, in a low coal price scenario, imported and domestic coal could reach effective price parity (defined as equal generation costs for modern power stations burning imported and domestic coal) at a relatively low price level by about 2020. In real life, the price situation may fluctuate between the two scenarios.

Looking at renewable generation as an alternative to coal, it is clear that hydro is and will remain India's cheapest source of power. Wind power is cheaper than power from imported coal in southern India: if international prices develop as forecast by the IEA, it will be cheaper in much of the country by 2020. The IEA forecast is for relatively constant prices at levels slightly lower than the average of the last few months – it probably does not represent an upper bound to the possible price range. The implication is that a significant increase in the proportion of India's electricity supply contributed by renewable generation would not constitute a major economic disadvantage to the country.

India's energy planners have been able, in the past, to fall back on the comfortable assumption that domestic coal will be cheap and plentiful. Future energy policy must be based on presumptions of high cost marginal coal supplies, with price volatility and increased levels of economic risk. The low cost of hydro power and the falling price of wind generation are strong arguments for further increasing the role of renewable generation as a means of reducing risk.

The cost of power from solar PV is falling rapidly but even in the high coal price scenario, it will still be more than 60% more expensive than coal power from the marginal plant in 2020. Solar PV – even if it can be combined with storage - will not be a contender to replace coal as a baseload technology for the foreseeable future, but distributed generation – including solar – could be a means to take the pressure off the conventional generation system.

9: What can an analysis of CDM projects tell us about the financing of greenhouse gas emissions reductions in India?[130]

9.1: INTRODUCTION

Based on data from the IEA's *World Energy Outlook 2011*, coal fired power stations in developing countries will account for 20% of global energy related emissions of CO_2 in 2020, even in a scenario that assumes that these countries make efforts to cut emissions. India and China alone will account for 17% of the global total (IEA, 2011). Even relatively limited progress in substituting renewables based power generation for coal in these countries would result in a significant reduction in global greenhouse gas (GHG) emissions.

International climate change negotiations since the Bali conference in 2007 have accepted that developed countries should partly fund the cost of cutting developing world GHG emissions, possibly by means of one or more new market mechanisms (NMMs). Market-based approaches have potential advantages - see (Coase, 1960; Montgomery W D, 1972) – but these have to be balanced against the fact that the Clean Development Mechanism (CDM) – an old market mechanism - has been the target of severe criticism. A particularly serious – and in our view valid – criticism is that many CDM projects are not additional: they would be implemented anyway, even without the CDM subsidy. David Victor has stated that, in his view, one third to two thirds of CDM projects are not additional (Victor, 2011). One researcher's opinion is not proof, but of about 250 experts who participated in a worldwide Delphi survey made by Germany's Oeko-Institut, 86% believed that carbon revenues are not a decisive factor in the investment decision for CDM projects and 71% believed that many projects would be

[130] By Ian Partridge and Dr Shama Gamkhar – work in progress. Dr Gamkhar is co-Chair of Ian Partridge's dissertation committee.

implemented in the absence of the CDM (Cames et al., 2007).[131] Non-additionality implies that, if offset credits are issued in the absence of real emissions reductions created by the CDM, the purchaser of these credits – maybe a participant in the European Emissions Trading Scheme - is able to increase carbon emissions. Total global emissions increase and real damage is done (Fischer, 2005).

An idea that has gained many followers is that future market based schemes should be sector-specific (de Sépibus and Tuerk, 2011; Lewis, 2010; Wooders, 2011). An attraction of a sectoral crediting mechanism (SCM) is that its rules could be written for a specific type of project – a possible cause of many of the problems experienced with the CDM is that its rules have to accommodate every conceivable type of project that might reduce GHGs. The future of carbon finance may lie in combining a number of sector-specific market based schemes with finance provided through direct grants or soft loans.

In this research we analyze the economics of Indian projects that reduce GHG emissions by substituting renewable generation technologies for coal. Our objectives are (1) to assess how grid-connected renewable generation might fit into a sectoral crediting scheme that might be combined with a direct financing approach; and (2) to propose and test a methodology to assess additionality in the specific case of grid-connected low carbon electricity generation projects. Our analysis is based on estimates of generation costs for renewable technologies and for the coal fired baseline plant: we combine these generation cost estimates with the calculated level of CO_2 emissions from the coal fired baseline plant to obtain estimates of the marginal abatement cost (MAC) of CO_2 by substitution of renewable generation for coal. The same generation cost estimates provide a basis for determination of project additionality using an approach described in the next section.

[131] See http://www.umweltdaten.de/publikationen/fpdf-l/3294.pdf (accessed August 15 2012).

9.1.1: Determination of additionality

A project is additional for the purposes of the CDM if "anthropogenic GHG emissions by sources are reduced below those that would have occurred in the absence of the registered CDM project activity".[132] The level of emissions that would have occurred in the absence of the project activity is known as the baseline. CDM rules permit two principal approaches to the determination of additionality:[133]

- **Barrier analysis**: a project is additional if barriers exist that would prevent its development in the absence of registration as a CDM project activity, and these barriers do not affect at least one alternative to the project.
- **Investment analysis**: a project is additional if it fails to meet a standard profitability benchmark or if it is financially less attractive than at least one alternative project.

The investment analysis approach appears to be both objective and verifiable but, in the specific case of low carbon generation, it suffers from the problem that additionality is effectively determined by the electricity tariff. In most developing countries this is set by some arm of government, which is unlikely to take a disinterested stance. We propose an alternative approach to determination of additionality that focuses on cost, not revenue, reducing the scope for manipulation of the assessment.

In many countries, one generation technology or fuel has clear economic advantages over alternatives: in India, this baseline is coal. We propose that, in countries where a baseline technology can be defined, a project is not additional if it generates electricity more cheaply than the marginal baseline plant as it would be economically rational to

[132] Paragraph 43 of decision 3/CMP.1.

[133] There are two others: projects in some categories are simply deemed to be additional – this currently applies only to industrial gas incineration; and a test of whether a project follows common practice is used as a check when a project has been determined to be additional using investment analysis or barrier analysis (Schneider, 2007).

build it anyway. Projects with higher generation costs than the baseline are additional and should be eligible to receive credits from a sector-specific offset scheme. Generation costs and emission reductions per unit generated should be assessed by technology, not project by project. They should be reviewed periodically as advances in technology are likely to change the relative cost picture. A scheme of this type that applied to only two countries – China and India – would cover 17% of all global energy related emissions in 2020 based on the IEA's New Policies scenario (IEA, 2011). Inclusion of other coal-dependent countries would increase this proportion.

The proposed method would disallow some projects that might have lower generation costs than the baseline but face barriers that would prevent their implementation – a typical barrier might be distance from a connection point to the regional transmission grid. However there is no obvious reason why a subsidy proportional to units of electricity generated by one project would solve this problem – a better (and probably more cost-effective) solution might be a subsidy from developed countries to fund extension of the grid.

9.1.2: Summary of analysis and conclusions

Our key findings are:

- Small hydro plants have negative MACs as they have the lowest generation cost of the technologies assessed in this paper. Our suggested methodology would indicate that these projects are non-additional, raising questions about whether they should be eligible for the CDM program.
- As output of domestic coal has apparently reached a plateau, the marginal source of energy for India is imported coal. We use a scenario approach to forecasting the costs of generation based on imported coal, as international coal prices are highly volatile. In a scenario based on IEA forecasts, the cost of wind generation in much of India in 2020 is below the cost of power from the marginal coal fired plant: based on

our proposed criterion, wind generation should then lose its eligibility for offset credits. However, as future MACs are highly dependent on the course of international coal prices, we suggest that relative costs should be reviewed periodically and the eligibility of different technologies for offset credits adjusted.

- The MAC of solar PV is positive throughout the period covered by this study - these plants are clearly additional and should be eligible to receive offsets. We suspect that the same is true of solar thermal, but we have no Indian data on which to base an analysis.

Our methodology is described in section 9.2 and our empirical findings are presented and discussed in detail in section 9.3 and 9.4: section 9.5 provides conclusions.

9.2: Description of Methodology

We estimate current and projected generation costs for wind, small hydro and coal fired generation – the methodology employed and the most important data sources are summarized below.[134] For the baseline plant - defined as the marginal coal fired plant (the next to be built) - we estimate the level of CO_2 emissions per unit of electricity generated. We calculate both current and projected marginal abatement cost (MAC) for cutting emissions by substitution of one technology for another using the identity

$$MAC = \Delta Generation\ Cost / \Delta\ Emissions$$

where *Δ Generation cost* signifies the difference in generation cost per kWh between technology (1) and technology (2) and *Δ Emissions* is the reduction in emissions per kWh achieved by the substitution. Our estimates of *Δ Emissions* are simplified in that the reduction in emissions due to the displacement of coal fired generation is taken as the average level of emissions per kWh for coal (the validity of this assumption is discussed

[134] The estimates and projections are taken from earlier papers by one of the authors (Partridge, 2012a, b). Readers requiring more detail of the methodology are referred to these papers.

in section 9.2.4), and emissions from wind and small hydro plants in operation are taken to be zero.[135]

9.2.1: Calculation of generation cost - wind and hydro

We estimate the generation cost for each project in the sample using the identity:

$$Generation\ Cost\ per\ MWh = operating\ cost + capital\ cost + intermittency\ cost$$

Operating cost is assumed to remain constant in real terms over the life of the project. **Capital cost** means initial investment cost annualized using the annual capital charge (ACC) methodology - see (Merrett and Sykes, 1973). **Intermittency costs** arise because the output of a wind turbine fluctuates due to the intermittency of the wind resource,[136] imposing costs on the grid operator due mainly to the need for additional conventional generation as backup. An analysis of intermittency costs would require a complex simulation exercise for the whole Indian grid, however a review of fifteen European and US studies (Holttinen et al., 2009) indicates that a conservative estimate of the added cost where wind contributes up to 5% of total supply to a grid would be \$1.50 per MWh.[137] Wind contributed only 2% of Indian electricity generation in 2009 (IEA, 2011).

Small hydro plants often operate on a seasonal basis depending on rainfall, but during the period of operation output is reasonably predictable. Added costs due to intermittency are assumed to be zero.

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[135] We ignore methane emissions from recently filled reservoirs. These mainly affect schemes with large reservoirs - our sample of hydro projects comprises primarily run of river schemes.

[136] The same is true of solar. In the limited analysis we have been able to do of solar PV projects in India we assume the same level of intermittency costs as for wind projects.

[137] Many of these studies include estimates of the cost impacts of various levels of wind contribution to total generation. Extrapolating back to 5%, the median added cost is about \$1.3, so \$1.5 is conservative.

Cost data for renewables are obtained from the UNFCCC database of registered CDM projects – see (http://cdm.unfccc.int/) - the approach used by (Partridge and Gamkhar, 2010). The project design documents (PDDs) on the website are a valuable data source – they currently provide operating and financial details of more than 4,000 registered projects. Our sample comprises 100% of grid-connected wind and small hydro generation projects in India that had been registered as CDM projects as of 12/31/2011.

The PDDs for some projects – in particular those registered prior to 2008 – do not provide sufficient data to allow calculation of a generation cost. Data are missing for 19 out of 249 wind projects (of which 17 are dated 2007 or earlier) and 30 out of 87 hydro projects. For all projects at least some data are available, enabling comparisons to be made between usable and non-usable projects on the basis of investment cost per MW (for most missing data projects) and project size (for all projects). We find no indication that the bias towards early projects distorts our results – for details of the statistical tests used, please refer to the relevant paper (Partridge, 2012b).

9.2.2: Calculation of generation cost - coal fired plants

It is first necessary to define the marginal coal fired plant: until a few years ago this would have been the 500MW subcritical unit designed by Bharat Heavy Electricals Limited (BHEL), optimized to burn domestic coal. Future coal fired plants are likely to use supercritical[138] technology - at least one such plant is already operating – and imported coal is now the marginal source of energy for India (Partridge, 2012a). We use both the former subcritical standard and a modern supercritical unit as baselines: we

[138] A supercritical plant operates at a higher temperature than the older subcritical design, raising its efficiency and enabling it to burn less coal and generate less CO_2 for the same power output; however the high working temperature requires the use of more advanced materials in its construction. Subcritical plants use domestic technology but Indian manufacturers must turn to foreign suppliers for some elements of supercritical plants, increasing plant costs.

assume the use of domestic coal for all locations and make an additional baseline assessment based on imported coal for coastal locations only.

Assumptions on plant efficiency, capital and operating costs for coal fired plants are taken primarily from project PDDs, many of which use the BHEL 500MW unit as the baseline. We also obtain data on supercritical plants from PDDs as several such plants have been put forward for CDM registration on the grounds that they cut CO_2 emissions per unit of electricity generated due to their high thermal efficiency. Data from PDDs are checked against sources such as reports of regulatory hearings and studies such as (MIT, 2007). Our understanding of the various sources mentioned above was much helped by contacts with engineers at the Indian Central Electricity Authority (CEA).

The largest operating cost element for a coal fired plant is coal. Pithead prices for domestic coal are published by Coal India Limited (CIL). We add royalties and other levies related to resource use but we do not add taxes on profits or value added as we take the view that these are not part of the cost *to the country* of power from a new plant. Coal quality parameters are based on the specifications of coal sampled at Dadri power station by a team from Ohio State University,[139] which are typical of grades supplied to thermal power stations in India, with high ash content (38.22%) and low sulfur (0.5%). Energy content (Gross Calorific Value, or GCV) is 3692 kcal/kg. The Indian Ministry of Environment and Forests requires that coal with ash content no greater than 34% should be used in any power station located in an environmentally sensitive area, or where the distance from mine to power station is more than 1000 km. We estimate the cost of washing and the effect on coal quality using data provided by the CEA.

The cost of coal delivered to a plant includes rail freight. We analyze likely supply patterns for new plants and use tables published by Indian railways to estimate delivered cost of coal by region. As most of India's coal mines are located in the Eastern

[139] See http://www.osc.edu/research/archive/pcrm/emissions/coal.shtml.

and Central part of the country, our hypothetical marginal power plant in this area would be located at the pithead. For non-pithead plants we define supply regions based on average distance to a mine that is capable of increasing production (as determined by analysis of production forecasts made for India's five year planning process). Delhi and industrial regions in Northern India are on average about 900km by rail from mines capable of increasing output significantly; a band from 900km to 1,300km covers most other important industrialized centers, while incremental coal supplies to South Western India must travel more than 1,700km by rail. Assam and the Northeast are separate from the rest of India in coal supply terms and are excluded from our analysis.

Imported coal is becoming an increasingly important component of India's energy supplies. The IEA's *World Energy Outlook 2011* forecasts that India's coal demand will more than double between 2010 and 2035 (IEA, 2011), however output of domestically mined coal is failing to keep pace. According to a recent press report, the state owned Coal India Limited (CIL) has warned its power sector customers that it can supply only 60% of their requirements: it hopes to be able to increase this to 80% within a few years.[140] Many existing power stations are blending up to 15% of imported coal with their supply from CIL, and many new power stations are designed to burn 100% imported fuel: in the interests of simplicity, we assume that our baseline power stations burn either 100% domestic coal or 100% imported.

Currently, most of India's imports of thermal coal come from Indonesia: we base our calculations on the specifications of benchmark grade Indonesian coal with energy content (GCV) of 6322 kcal/kg. For simplicity, we assume that the freight costs from any Indonesian loading port to any Indian discharge port are the same – we believe that the

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[140] http://articles.economictimes.indiatimes.com/2012-06-06/news/32079088_1_coal-supply-coal-india-power-plants (accessed July 15 2012).

error introduced is minimal. Our assumptions concerning the price of imported coal are summarized in the next section.

9.2.3: Price scenarios for coal imports

Our generation cost projections are essentially levelized costs of electricity (LCOE) – i.e. the average cost over the life of the plant discounted back to the base year. For most cost elements it is sufficient to assume that costs remain constant in real terms, however this is not a reasonable assumption for prices of internationally traded coal, which are highly volatile: we base our estimates on two scenarios that we believe provide upper and lower bounds for import prices.

- The lower price scenario is based on the fact that coal is a quintessential commodity - in the long term prices should fluctuate around the long run marginal cost (LRMC) of new supplies, which may change over time (Pindyck, 1999). A report on power generation in India (Mott McDonald, 2006) assumed an LRMC for Pacific basin exporting countries of US$40 per ton[141] fob loading port. A realistic estimate today would be about $50 per ton fob (IEA, 2010, quoting data from Marston and IHS Global Insight). For our lower bound forecast we use a figure of $50 per ton (2010 Dollars) fob Indonesian loading port, which we assume to apply from 2015.
- For our upper bound scenario we adapt forecasts made by the IEA for its annual World Energy Outlook (2011 edition) - specifically, the New Policies Scenario, which is based on energy-related policies announced (but in some cases not yet implemented) by both OECD and non-OECD countries. Our "IEA" scenario is the IEA's New Policies forecast adjusted for coal quality.

Our price forecasts for 2020 for both domestic and imported coal, adjusted to a common currency basis, are shown in table 9.1 for a location on the West coast of India.

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[141] Metric tons are used throughout this paper.

Table 9.1: Delivered Cost of Coal in 2020 – India West Coast ($(2012)/t)

	Domestic	Imported	
		LRMC	IEA
Pithead price	793	2,861	5,480
Freight & Handling	1,384	1,102	1,102
Royalty etc	225	25	25
Delivered Cost	2,402	3,989	6,607
GCV (kcal/kg)	3692	6322	6322
Delivered Cost (US$/GJ)	2.63	2.77	4.59

9.2.4: Reduction in emissions due to use of renewable generation

We estimate CO_2 emissions for a plant burning Indian coal using an emission factor of .0967 tons CO_2 per GJ (NCV basis) reported by (Roy et al., 2009): for imported coal we use the IPCC default emission factor of .0946 t/GJ. Other greenhouse gases are ignored - a modern coal-fired power station emits negligible quantities of nitrous oxide;[142] the effect of particulates on warming is significant but hard to estimate, and their residence time in the atmosphere is short.

To simplify the calculation, we assume that the reduction in emissions due to use of renewable generation is equal to the average emissions rate of a coal fired plant (Callaway and Fowlie, 2009; Kaffine D et al., 2011). This assumption is not generally true - studies show that adding renewables to an existing generation system typically displaces some mix of coal and gas (Kaffine D et al., 2011) rather than just coal; however in this research we examine the effect of additional renewable generation capacity on plant construction, not on dispatching decisions (short term decisions by grid operators on which units should vary their output as demand fluctuates). If Indian energy planners maximize construction of gas fired and large hydro plant regardless of the

[142] See http://www.epa.gov/ttnchie1/ap42/.

renewable contribution to total generation, we can assume 1:1 substitution of renewables for coal in terms of new plant construction.

Even given 1:1 substitution, the net emissions reduction achieved is less than the average emissions rate of a coal fired plant. Grid operators anticipate fluctuations in wind generation by operating some conventional plants at reduced output levels so they can be quickly run up to full power when required. A partially loaded plant is less efficient than a plant at full load and thus has higher CO_2 emissions per unit of power generated (Kaffine D et al., 2011).

A study of regional grids in Texas, California and the Midwest of the US shows the extent to which the share of coal in total generation affects the net reduction in CO_2 emissions per MWh of wind generation (table 9.2). In the Midwest, where generation is predominantly coal fired, each MWh of wind generation corresponds to a reduction in CO_2 emissions of 0.93 tons[143]- close to the average emissions level of a coal fired plant in the US, which is 1.0 ton/MWh (Kaffine D et al., 2011). It seems likely that the error introduced by our use of average emissions as a proxy for net reductions is small.

Table 9.2: Reduction in CO_2 emissions due to wind generation

	% Generated by Coal	% Generated by Wind	Reduction in CO_2 Emissions per MWh Wind
Midwest	80%	2.0%	0.93 tons
California	0.0%	3.2%	0.27 tons
Texas	37%	4.7%	0.44 tons

Source: (Kaffine D et al., 2011)

[143] All emission rates quoted are taken from Kaffine et al (2011), converted into metric units.

9.3: Results – generation costs

Estimated generation costs for domestic and imported coal for 2011 are shown in table 9.3. It can be seen that, in 2011, a new plant fuelled by domestic coal produced electricity more cheaply than a new plant of the same type using imported coal - even in Southwest India, where the cost of domestic coal includes rail freight over 1,700km. Where coal prices are high, the higher efficiency of the supercritical plant gives it a cost advantage over subcritical technology, however with low coal costs – as with domestic coal in the pithead supply region – subcritical generation is (slightly) cheaper.

Table 9.3: Baseline Generation Costs for 2011 (INR(2012)/kWh)

Coal type and plant location	Subcritical	Supercritical
Domestic Coal (Pithead Supply)	1.23	1.34
Domestic Coal @ 900km	1.92	1.96
Domestic Coal @ 1,300km	2.16	2.17
Domestic Coal @ 1,700km	2.39	2.38
Imported Coal (Coastal Location)	3.23	3.17

For wind generation, we estimate a regression model for 2005-2011 with the log of generation cost as dependent variable – see table 9.4. The negative coefficient on log of cumulative installed capacity indicates that costs fall with experience of the technology, while the negative is_south variable indicates that costs are lower in the South - as of August 2011 this region has 42% of India's total wind capacity (Ministry of New and Renewable Energy – www.mnre.gov.in). Note that project size is not in the final model. A similar analysis for hydro generation (57 observations) shows no significant learning effect – this is not surprising as the technology has changed little over several decades. There is some scale effect and generation costs are lower in the North.

As of March 2012, two grid-connected solar PV projects had been registered as CDM projects in India. Their generation costs, calculated using the same methodology as the figures for wind and hydro presented above, are INR 11.2 and INR 14.4 per kWh (2012 currency). The cost of solar power is falling rapidly: a recent McKinsey and Co report (Aanesen et al., 2012) forecasts that LCOE for large solar PV installations will be about INR 5 per kWh (2012 currency) by 2020.

Table 9.4: Generation Cost Analysis – Wind

Dependent variable:	log of generation cost (INR(2012) per MWh)
N:	240
R^2:	0 .4375
Adjusted R^2:	0.4328

	Coef.	Std. Err.	t	P>|t|	95% conf. interval	
Log_cum	-0.206	0.028	-7.38	0	-0.262	-0.151
Is_south	-0.173	0.015	-11.81	0	-0.201	-0.144
Constant	10.142	0.261	38.84	0	9.627	10.656

Notes: Log_cum is the log of cumulative installed capacity in MW;

Is_south is a dummy variable (=1 if project is located in Southern grid region)

Table 9.5 shows our cost estimates for grid-connected wind and small hydro in 2011 (i.e. for projects commissioning in 2011), as predicted by the regression models described above. Small hydro exhibits a scale effect: our estimates are for a 25MW unit. Projected costs to 2020 for all technologies are shown in Chart 8.3.

Table 9.5: Cost of wind and small hydro Generation 2011 (INR(2012)/kWh)

Wind:	South	2.97
	Rest of India	3.53
Small Hydro:	North	1.59
	Rest of India	1.82

9.4: RESULTS - MARGINAL ABATEMENT COSTS

The marginal abatement cost (MAC) to cut CO_2 emissions by substitution of a renewable generation technology for a baseline coal fired plant is defined here as the increase in generation cost per kWh divided by the decrease in emissions per kWh. For new plants commissioning in 2012, the baseline plant might use subcritical or supercritical technology and might burn domestic or imported coal, depending on location: by about 2015, in our view, the marginal plant will use supercritical technology as the majority of large coal fired plants currently at the planning stage are supercritical units. In most of India the marginal plant will burn imported coal as there appears to be little possibility of significantly increasing output of domestic coal.

Tables 9.6a and 9.6b show MACs for wind and small hydro, stated in 2012 currency, compared to alternative baselines. It is apparent that:

- MAC for small hydro projects is always negative, regardless of location or baseline, as small hydro is the cheapest generation technology for India (see chart 8.3).
- For wind projects and for comparisons where the baseline plant burns imported coal, tables 9.6a and 9.6b show a more complex picture:
  - In 2011, prices for internationally traded coal peaked and wind generation was the cheaper technology, at least in the South of India, implying that its MAC against imported coal was negative.
  - If coal prices remain high, as forecast by the IEA, this situation will last throughout the period covered by our forecasts. However in the LRMC (lower bound) price scenario, MAC for wind power in Southern India will be positive in 2012 and for the foreseeable future.
- In the rest of India, wind generation will be more expensive than coal in both price scenarios, at least until 2020, meaning its MAC will be positive.

Table 9.6a: Marginal Abatement Cost ($/tCO₂); plant startup 2012

LRMC Scenario		Subcritical		Supercritical	
		Domestic	Imported	Domestic	Imported
Wind:	West Coast	24.3	20.4	27.0	22.3
	Southwest	9.2	9.6	10.6	10.4
	Southeast (Tamil Nadu)	14.2	9.6	15.7	10.4
Hydro:	Delhi/North	(4.9)	N/A	(6.6)	N/A
	South & West Coasts	(5.7)	(11.7)	(6.8)	(13.3)
	Southwest	(10.8)	(11.7)	(11.9)	(13.3)
IEA Scenario					
Wind:	West Coast	24.3	5.2	27.0	7.1
	Southwest	9.2	(5.5)	10.6	(4.8)
	Southeast (Tamil Nadu)	14.2	(5.5)	15.7	(4.8)
Hydro:	Delhi/North	(4.9)	N/A	(6.6)	N/A
	South & West Coasts	(5.7)	(31.3)	(6.8)	(33.3)
	Southwest	(10.8)	(31.3)	(11.9)	(33.3)

Table 9.6b: Marginal Abatement Cost; plant startup 2015/ 2020

($ (2012)/tCO₂)

Plant startup year & price scenario		2015		2020	
		LRMC	IEA	LRMC	IEA
Wind:	West Coast	22.4	3.4	18.8	(1.4)
	Southwest	11.2	(7.8)	8.2	(12.0)
	Southeast (Tamil Nadu)	11.2	(7.8)	8.2	(12.0)
Hydro:	Delhi/North	(6.6)	(6.6)	(6.6)	(6.6)
	South & West Coasts	(8.6)	(27.6)	(7.8)	(28.1)
	Southwest	(8.6)	(27.6)	(7.8)	(28.1)

Note: Estimates for 2015/2020 are for a supercritical unit. It is assumed to burn imported coal except in Delhi/North, where domestic coal is assumed.

Estimates of MAC provide an indication of the incentive needed to stimulate investment in the technology concerned - in principle, the MAC is the carbon price at which the project would be economically viable without further subsidy. Tables 9.6a and 9.6b show that small hydro always has a negative MAC while the wind power MAC against imported coal is negative in the high price (IEA) scenario, at least in coastal regions in the South. In these cases no production-linked incentive is required. In the low price (LRMC) scenario, a carbon price in the region of \$25/ton in 2012, falling to below \$20/ton by 2020, would eliminate the price disadvantage of wind power relative to marginal coal fired plants in much of India. In Southern India, where wind costs are lower, a carbon price of around \$10 would be sufficient. Based on McKinsey's estimate of the generation cost for solar PV in 2020 (see section 9.3), MAC for solar in 2020 will be \$42/tCO_2e in the IEA scenario and \$62 in the LRMC scenario.

These "target" carbon prices can be compared with the IEA's projections for the New Policies scenario. This assumes that Korea will implement an ETS by 2020; the US and Japan will introduce shadow pricing of carbon by 2015; and China will introduce some form of CO_2 pricing by 2020, all against a background of steady global growth. In this situation, the IEA projects a carbon price of \$30/tCO_2e in 2020 in the EU, New Zealand and Australia, with lower prices in China and Korea. Shadow prices in the US and Japan start at \$15/tCO_2e in 2015 and rise to \$35 in 2035 (all carbon prices stated in 2010\$).

Another source of carbon price projections is the report of the UNFCCC's High Level Advisory Group on Climate Change Financing.[144] This puts forward three carbon price projections for 2020: \$10-\$15; \$20-\$25 and \$50. The first two of these are consistent with the implementation (with different degrees of enthusiasm) of pledges made after the Copenhagen conference. The report does not mention macroeconomic assumptions, but it is apparently not based on economic modelling.

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144 http://www.un.org/wcm/content/site/climatechange/pages/financeadvisorygroup/pid/13300

It appears that neither forecast would be consistent with a sharp slowdown in the rapidly developing Asian economies. Although our LRMC scenario is based on the economics of coal production, we believe it would most likely be triggered by a sharp fall in international coal demand (or, less likely, a sharp increase in supply). It therefore provides an indication of the impact on energy markets of a slowdown in the "tiger" economies, which would significantly reduce regional coal demand. In a world where growth in these economies remained slow in the long term, the carbon price might settle at too low a level to stimulate significant investment in renewable generation.

9.4.1: Should supercritical plants receive offset credits?

In recent years, a few supercritical coal fired plants in India have applied for registration as CDM projects. The rationale is that the supercritical plant, due to its higher efficiency, burns less coal than the baseline subcritical plant to produce the same electricity output and thus emits less CO_2. This argument is seen as controversial in some quarters: many environmentalists take the view that the CDM should not be rewarding investment in coal fired plant of any type. However, ignoring this philosophical controversy and looking at the economics, we can use our generation cost estimates to calculate a MAC. Table 9.6c shows estimated MACs for the case where a subcritical plant is substituted by a supercritical plant burning the same coal.

Table 9.6c: Marginal Abatement Cost (\$/tCO_2e); supercritical vs subcritical

Coal source & price scenario	Domestic	Imported	
		LRMC	IEA
Pithead Supply	21.5		
Delhi	7.9		
Southeast, West & Punjab	3.0	3.0	(11.7)
Bangalore & Southwest	(2.1)	3.0	(11.7)

Note: for plants commissioning in 2012

The economics of this substitution depend largely on the assumed price of coal – with a high coal price, the higher capital cost of the supercritical unit is more than offset by lower fuel costs due to its greater efficiency. Where the proposed fuel is imported coal, MAC is negative in the IEA (upper bound) price scenario and (just) positive in the LRMC (lower bound) scenario. With domestic coal, MAC is negative only in the far Southwest of India where the delivered cost of domestic coal is high due to high rail freight costs. We conclude that:

- A supercritical plant burning imported coal is (marginally) additional today if one assumes that international coal prices will remain low in the long run; otherwise not.
- In most of India a supercritical plant burning domestic coal is additional; however this is partly due to the low domestic coal price. It could be argued that the international community subsidizes supercritical power plants through the CDM in order to offset a subsidy to subcritical plants provided by the Indian government.
- It is, in any case, increasingly unrealistic to take a subcritical plant as the baseline in calculating MAC. If a supercritical plant is the baseline, its MAC is zero by definition.

9.5: Conclusions - Additionality and the Design of Sectoral Offset Schemes

One objective of this paper is to review the effectiveness of generation cost comparisons in assessing additionality. David Victor believes that an improved CDM without the loopholes that allow registration of non-additional projects would be very small (Victor, 2009): to achieve meaningful scale would need a change in emphasis from project-by-project additionality to a broad focus on whether a scheme channels funds towards lower carbon technologies on a large scale (Grubb et al., 2011) - this would require a reasonably accurate measure of additionality for categories of project, rather than individual projects. In our view, our proposed method can provide such a measure. Applied to an offsets scheme for renewable generation in India, it would indicate that:

- MAC for small hydro is negative - this suggests that small hydro projects, at least in India, are not additional and should not receive offset credits.
- The cost of wind generation in India is falling: future cost differentials (and therefore MACs) depend on coal prices. If these develop in line with IEA forecasts and if wind generation costs continue to fall, wind power in Southern India will be cheaper than power from the marginal coal fired plant and its MAC will be negative throughout the period. In the rest of India, MAC will be positive until 2020, based on the IEA forecasts, while in the low price (LRMC) scenario, MAC will be positive throughout. Additionality, in this situation, becomes a dynamic rather than a static concept: the relative costs of wind and coal generated power should be reviewed periodically.
- After a short transition, supercritical coal fired plants will be India's marginal generation technology: as such they will be the baseline for calculation of MAC and ineligible to receive offsets.
- MAC for solar PV is positive and the technology meets our test of additionality. This technology should qualify for subsidies through any future NMM or other direct funding mechanism applicable to the energy sector. We expect that the same is true of solar thermal, but we have no Indian data on which to base an analysis.

Our methodology and analysis create a basis for the design of a sector-specific agreement such as those envisaged by the EU that would ensure additionality on a sectoral basis, avoiding the delays and additional costs caused by project by project assessment. It would retain the CDM's advantage of providing incentives directly to project developers and, in our view, would be simpler to administer than the CDM and a considerable improvement on that scheme in terms of environmental integrity.

APPENDIX: CALCULATION METHODOLOGIES AND DATA SOURCES

AI: INDIA - COAL-FIRED PLANT

A1.1: Plant efficiency and costs

The Indian government has designated successive generations of coal fired boilers as the national standard: (Chikkatur A., 2008) states that "the current standard for coal-power technologies in India is the BHEL 500 MW subcritical PC (pulverized coal) unit". The UMPP program ended this tightly controlled approach as the choice of boiler was left to the bidders, who seem to have ignored a government press release stating that the new standard would be a 3X660 MW supercritical plant. We base our calculations on alternative baselines: a 2X500 MW subcritical plant and a 3X660 MW supercritical.

For both baselines the parameters used are averages of values obtained from a number of sources. Our supercritical baseline is an amalgam of data from PDDs of units that applied for CDM registration (Sasan, Tirora, Mundra/Tata and Mundra/Adani) and a report by Mott McDonald. This covers several types of unit – we use the data for a "base supercritical" unit. The wide spread of PDD values may indicate that some of them relate to Mott McDonald's "high supercritical". (Mott McDonald, 2006)

For the subcritical baseline, sources include data from the PDDs mentioned in the previous paragraph plus a report of a regulatory hearing posted on the CERC website that relates to a modern 500MW plant.[145] We also use data from *The Future of Coal* (MIT, 2007) - these relate to a plant with flue gas desulfurization (FGD) but we adjust for a plant without FGD assuming that the FGD unit consumes 2% of the plant's output (the report states that own use consumption by the FGD unit is between 1% and 3%). The

[145] The plant concerned is Rihand. We ignored data in regulatory documents that appeared to be based on allowed rather than actual or design values - the allowed values used in regulatory documents are sometimes inconsistent with current plant performance.

MIT data are for a plant burning Illinois No 6 coal: this has lower ash content than Indian coals, however adjustment factors for lower quality coals are provided. The CEA website provides actual heat rates for some plants, however the only 500MW subcritical plant included is Trombay, which for various reasons cannot be taken as representative.

In all cases, the sources mentioned provide a range of values for any given parameter – we calculated average values over the range. In deciding whether to include outlying values in the averages we relied partly on guidance from CEA engineers.[146] All the figures used are adjusted to a gross output/GCV basis.

Table A1: Efficiency on Gross/GCV basis

	Subcritical		Supercritical	
	Domestic	Imported	Domestic	Imported
CEA figures (AK Gupta) - OHR	35.4%		38.3%	
MIT adjusted	35.3%	37.5%	39.6%	41.9%
Booras & Holt (from MIT)	36.6%	38.9%		
PDD Averages	35.6%	35.3%	39.7%	40.9%
Trombay design rate	35.6%			
Mott McDonald base			40.6%	41.8%
Mott McDonald high			42.3%	42.8%
Value Used	35.5%	37.2%	40.0%	41.2%

We estimate per-unit capex and O&M (Operation and Maintenance) costs using the sources mentioned above, omitting the Mott McDonald figures which reflect costs in advanced countries (for supercritical they are close to the Indian data – presumably reflecting Indian engineers' reliance on foreign input in the construction of these plants). We adjust these figures for inflation using the composite index (60% WPI and

[146] Particularly A.K. Gupta, Chief Engineer (Technology) and Amarjeet Singh, Chief Engineer (Emissions). Both contacted during research visit to New Delhi, October 2011.

40% CPI) used by Indian regulators. We ignore the use of secondary oil fuel, and disregard the PDD figures for plant life, which reflect regulatory norms rather than reality (we use 40 years). The own-use figures in the PDDs (other than for Sasan) also seem to reflect regulatory norms: on the advice of A.K. Gupta, we use the average own use figure for 500 MW plants for 2007-2008, taken from the CEA Performance Review to apply to both subcritical and supercritical plants.

The CAPM estimate of the expected post-tax return on equity (RoE) for thermal generation in India is 15.7%, based on a risk-free rate equal to the rate on Indian government ten year bonds (8.654% as of April 27 2012) and the average market risk premium of 8.5% reported by 28 Indian respondents (academics and practitioners) to a survey made by a team from the University of Navarre (Fernandez et al., 2011). Beta for the Indian power sector is 0.83, according to an online dataset maintained by Professor Damodaran of the Stern Business School at New York University.[147] As the CAPM figure is very close to the CERC allowable return of 15.5% post-tax, we use the CERC figure.

We convert investment cost per MW to an annual capital charge (ACC) using a spreadsheet created by Hoff Stauffer of Wingaersheek Research Group – see (Stauffer, 2006). Plant life is taken as 40 years; debt ratio is the CERC norm of 70%; debt interest rate is 12.25% (prime lending rate of State Bank of India as of August 2010); tax rate is the current Indian rate including surcharge (i.e. 34%); inflation the average for 2005-2011. Depreciation for the purpose of calculating WACC is the current standard of 15% on the declining balance (note that this is depreciation allowable for tax purposes, not depreciation allowable in calculation of tariff).

[147] See http://pages.stern.nyu.edu/~adamodar/New_Home_Page/data.html. Version used was updated in January 2012; accessed April 30, 2012.

A1.2: Coal supply pattern

The price of coal delivered to the generating plant depends on plant location and supply source. We define supply regions by identifying mines capable of increasing production and estimating freight costs from these mines to key cities.

The combined output for 2010/11 for Coal India Limited (CIL) and the Singareni Collieries Company Limited (SCCL) - the two state owned coal mining companies - in the XI Plan (2007-2012) is 522.38 Mt, rising to 561.30 Mt in 2011/12. Preliminary figures (published November 2006) show coal production for the last year of the XII Plan (2016/17) of 709.00 Mt for CIL and SCCL, with a huge increase in "Other" – output from private mines (the official XII Plan figure was released too late for this research). Table A2 below shows the key figures taken from Planning Commission documents.

Table A2: Coal Output (Million tons)

Company	2011/2012		XII Plan 2016/2017	Increase on 2011/2012 Plan	2011/2012 1H Actual
	Plan	Estimate			
ECL	46.00	33.00	48.00	2.00	11.50
BCCL	30.00	30.00	35.00	5.00	12.54
CCL	78.00	51.00	115.00	37.00	16.93
NCL	70.00	68.50	80.50	10.50	24.95
WCL	45.00	45.50	45.00	0.00	19.53
SECL	111.00	112.00	140.00	29.00	49.46
MCL	137.00	106.00	197.00	60.00	41.50
NEC	3.50	1.00	3.50	0.00	0.21
CIL (Total)	520.50	447.00	664.00	143.50	176.62
SCCL	40.80	51.00	45.00	4.20	
Other	118.70	56.00	346.00	227.30	
All India	680.00	554.00	1055.00	375.00	

Actual production levels are below plan targets, however we assume that the originally planned output increases by company for 2016/17 over 2011/12 (table A2) give a reasonable indication of which companies can increase output during the next decade. Thus we assume that the principal marginal sources of new supplies of domestic coal will be CCL, NCL, SECL and MCL. Key mines belonging to these companies are North Karanpura (CCL), Singrauli (NCL), Korba (SECL), Ib Valley (MCL) and Talcher (MCL). Our analysis is based on supply to new power stations by rail transport from these mines.

The Indian Railways online route finder http://rbs.indianrail.gov.in/ShortPath/index.jsp provides estimated rail transport distances from these mines to India's ten largest cities, together with five other cities chosen for their geographic diversity (the analysis excludes Assam and the Northeast of India). The distance used for each city is the minimum of the distances from each of the mines – see Table A3. On the basis of this analysis we define the following supply patterns for new power stations:

- All new power stations in a large area in Eastern and Central India will be built at the pithead. SCCL's principal coalfields are included in the pithead supply area: they are not among those identified as able to increase output significantly, but it is assumed that any new supplies available will be consumed at pithead plants.
- The supply distance for Delhi and industrial regions in nearby states is 900 km (based on Delhi, Jaipur and Kanpur: incorporates much of Haryana and Eastern Rajasthan).
- The supply distance for principal coastal locations in the South and West is 1,300 km (Mumbai and Chennai: excludes coasts of Kerala and Karnataka). We use the same supply distance to most inland regions of Maharashtra and Gujarat as well as industrial regions North of Delhi. The far Northern states are assumed to be supplied primarily by hydro power.
- The supply distance for the far South West is in excess of 1,600 km – for calculation purposes a figure of 1,700 km is used (Bangalore, Kerala and Western Karnataka).

Table A3: Supply distances to key cities

City	State	Population[a]	Mine	Distance (km)
Mumbai	Maharashtra	12,478,447	Korba	1,340
Delhi	Capital Territory	11,007,835	Singrauli	914
Bangalore	Karnataka	8,425,970	Talcher	1,604
Hyderabad	Andhra Pradesh	6,809,970	Korba	999
Ahmedabad	Gujarat	5,570,585	Singrauli	1,269
Chennai	Tamil Nadu	4,681,087	Talcher	1,332
Kolkata	West Bengal	4,486,679	N. Karanpura[b]	358
Surat	Gujarat	4,462,002	Korba	1,235
Pune	Maharashtra	3,115,431	Korba	1,397
Jaipur	Rajasthan	3,073,350	Singrauli	974
Kanpur	Uttar Pradesh	2,767,031	Singrauli	481
Bhopal	Madhya Pradesh	1,795,648	Singrauli	659
Ludhiana	Punjab	1,613,878	Singrauli	1,201
Nashik	Maharashtra	1,486,973	Korba	1,158
Aurangabad	Maharashtra	1,171,300	Korba	1,173

Notes: (a) http://www.censusindia.gov.in/2011-prov-results/paper2/data_files/India2/Table_2_PR_Cities_1Lakh_and_Above.pdf

(b) Nearest loading point seems to be Chainpur

For an approximate indication of the boundaries of the supply regions, see Map 8.1. For each supply region, we calculate average rail transport costs using freight rate tables (http://www.indianrailways.gov.in/railwayboard/view_section.jsp?lang=0&id=0,6,338) that are posted from time to time by Indian Railways. We take no account of the use of coastal seafreight for long distance transport and make no attempt to estimate distribution costs of imported coal to inland locations.

A1.3: Prices of Domestic coal

We calculate the cost of pithead supplies based on CIL and SCCL prices posted on the two companies' websites[148] (pithead supplies in the South come partly from SCCL, which posts slightly higher prices for the same grade). We use weighted averages of prices for E, F and G grades, weighting by output. For CIL, We compute a weighted average price for each subsidiary and weight subsidiaries according to the expected increase in output during the XI Plan period.

Add-on costs (handling charges, royalties and similar payments) included in the delivered cost of coal are complex. A detailed breakdown is on the SCCL website, though it is not clear which cost components typically apply to supplies to thermal power stations. CIL does not provide a similar breakdown. In principle, we include all add-on costs that are likely to be paid by the average power station customer and that represent a charge for a service or use of a resource, meaning that we include royalties and forest-related charges but not excise, stowing excise or VAT. For the purposes of the analysis we do not include crushing or screening charges, or any surface transport charge, but we do include loading charges shown in the CIL and SCCL price notices. Table A4 shows typical figures taken from the SCCL document (for an E grade r.o.m. coal – price sheet applies from August 1 2011).

A1.4: Analysis of domestic coal

In the absence of valid data on coal quality by plant, estimates for all locations are based on the specifications of coal sampled at Dadri power station by a team from Ohio State University[149] and analyzed by NETL. More details of the analysis are provided in a USAid

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[148] http://www.coalindia.nic.in/pricing.htm and http://scclmines.com/downloads/coalprice.htm respectively.

[149] See http://www.osc.edu/research/archive/pcrm/emissions/coal.shtml.

feasibility study on the potential for IGCCs in India.[150] The Dadri sample is typical of grades supplied to thermal power stations in India, with high ash content (38.22%) and low sulfur (0.5%). Energy content (Gross Calorific Value, or GCV) is 3692 kcal/kg.

Table A4: Breakdown of SCCL price (INR/t)

Charge	Included	Not Included
Base Price	1,130	
Premium		339
Fixed Royalty	70	
Variable Royalty	56.5	
Royalty on Premium		16.95
Forest related charges	27	
Fuel Surcharge	48	
Clean Energy Cess	50	
Other		186.49[a]
Total	1,381.5	542.44

Note: (a) Stowing Excise Duty, Excise Duty and VAT. The SCCL price breakdown shows surface transport charge and lifting charge as zero. It shows a pre-weigh bin charge that we assume applies to road transport only.

The Indian Ministry of Environment and Forests requires that coal with ash content no greater than 34% should be used in environmentally sensitive areas or where the distance from mine to power station is more than 1000 km. Information provided by the CEA (Amarjeet Singh and A.K. Gupta) indicates that this regulation is observed but it is not entirely clear how – CIL has very limited washery capacity. However we assume washed coal is supplied to all locations outside the pithead supply region (Delhi is just

[150] See a presentation dated February 2008 at http://www.indiapower.org/igcc/standon.pdf (accessed July 1, 2012).

under the I,000 km limit but is assumed to require washed coal because it is a major population center). We assume that washed coal is blended with r.o.m. coal to give exactly 34% ash. The cost of washing and the effects on coal analysis are estimated based on information provided by the CEA (A.K. Gupta). It is standard international practice to burn washery rejects in a fluidized bed combustion (fbc) unit to generate electricity – it is unlikely that this is done in India. Ideally, our calculations should take account of both emissions from the fbc (if it exists) and the value of the power generated, however we have no data on which to base a calculation.

A1.5: Imported Coal

For coastal plants only we look at the economics of using imported coal. As of late 2011, India imports coal mainly from Indonesia. Much of our information on imports comes from Mr Arun Kumar of PTC Energy Ltd.[151] There is currently (late 2011) significant uncertainty about grades imported due to a major change in Indonesia's policy on export pricing: many project developers have negotiated electricity tariffs based on firm contracts for very low grade imported coal, which has historically been available at advantageous prices. However, those low price contracts have been unilaterally repudiated by Indonesia and developers are exploring alternatives. In the absence of better information, we use benchmark grade Indonesian steam coal as a reference for imported coal (GCV of 6322 kcal/kg).

We make no attempt to forecast the delivered cost of imported coal. Instead we rely on two scenarios that together cover the likely range of prices. For a low price scenario we adopt the approach taken by the Mott McDonald report, which bases its forecasts on an estimated long run marginal cost (LRMC) for Australian coal of $40/ton fob (Mott McDonald, 2006). The IEA's World Energy Outlook 2010 indicates that LRMC has increased by $10 due to factors such as congestion of rail routes to Australian ports that

[151] Visit to New Delhi in October 2012 and subsequent telephone contacts.

are likely to be long term (IEA, 2010). The opening up of mines in more remote areas such as Mongolia has probably also increased LRMC. Our base case forecasts for imported coal assume a fob price for benchmark Indonesian coal of $50 per ton in 2009, constant in real terms.

An alternative analysis – also for Australian coal – is provided in *An Analysis of Steaming Coal Price Trends* - see http://eneken.ieej.or.jp/en/data/pdf/159.pdf, which suggests that the cap on prices is set by the price that attracts US exports into the Pacific market (which is about $40 per ton). If this is the case, any disruption of the Pacific basin market due to lower economic growth in key countries could seriously destabilize this market as growth in US shale gas production is increasingly pushing coal producers in the western US into export markets.

Our high price scenario is the New Policies scenario from (IEA, 2011). The coal price forecasts in this document are for average OECD import prices: historic prices in the IEA documents have averaged about 93% of the Indonesian benchmark price and adjust the forecasts accordingly.

In both scenarios we apply a cost of freight, using an estimate of LRMC made by Mott McDonald for Panamax ships – past imports have been mainly in handysize vessels. Additional costs (port charges and local transport) are as advised by Arun Kumar. As with domestic coal, we add royalties and other charges that relate to services or use of resources only – for example, we add clean energy cess but not import duty. For both domestic and imported coal we ignore handling loss.

A1.6: CO_2 emissions

For domestic coal we use an emissions coefficient estimated by (Roy et al., 2009). For imported coal we use the IPCC default figure. We take no account of leakage effects such as emissions from mining. We assume that each MWh generated by renewables reduces system-wide CO_2 emissions by the average volume of CO_2 emitted per MWh generated by a coal fired plant. Research by (Kaffine D et al., 2011) indicates that the error introduced by this simplifying assumption is likely to be small (see section 9.2.4).

A2: CHINA – COAL FIRED PLANT

A2.1: Plant costs and efficiency

A draft report to the World Bank on renewable energy in China (Meier, 2003) contains a complete calculation of generation cost for certain regions of China for the year 2000. Our calculations are essentially an updated version of Meier's, broadened to cover all important regions and adjusted to remove taxation effects.

A 2006 IEA report notes that "the (Chinese) government encourages the construction of plants with a capacity of 600 MW or more" and "by the end of 2003, 83 plants with a capacity of 1,000 MW or more were in operation" (IEA, 2006). Supercritical technology is the standard for new construction of coal-fired power stations with capacity greater than 600MW (http://www.worldcoal.org/pages/content/index.asp?PageID=421). The IEA report *Cleaner Coal in China* notes that about 60% of all newbuilds in China are large supercritical units (IEA, 2009). We use a 2X600 MW supercritical unit as a baseline. O&M costs and capital investment for this plant are given in a document issued by "Power Planning Design Institution" that is referenced in the PDDs for many Chinese projects. Responsibility for this organization, which was formerly responsible for supervision of power plant construction, has been transferred to another Ministry. We use data from an unpublished version of the same document (dated 2009) provided by John Romankiewicz of Bloomberg New Energy Finance.

Capital cost is converted to an annualized capital charge rate using Stauffer's spreadsheet - see (Stauffer, 2006). Assumptions are taken from project PDDs: the debt interest rate is 10%; annual inflation is 2%; the tax rate is 33%; and the weighted average cost of capital is taken as 8%, which is the rate used by Chinese regulators.

Our figures for thermal efficiency of power plants are taken from *The Future of Coal* (MIT, 2007), which gives data for standardized conditions and for a plant burning Illinois No 6 coal. The MIT document provides adjustment factors for different conditions and coal grades – in our calculations we use the MIT figures adjusted for generic Chinese coal and to a Gross output/GCV basis (the MIT figures are for net output). We take account of the fact that all new Chinese coal fired power stations must be fitted with flue gas desulfurization – we assume that the FGD is actually operating, which is not always a certainty in China. Capital and operating cost of FGD are taken from (You and Xu, 2010); parasitic power requirement from (MIT, 2007). We assume that the FGD sulfur removal efficiency is 85% - this is a rough average of removal rates in operational FGD projects in China, though new wet FGD units apparently achieve 95%.

Sulfur removal affects operating cost not only through the direct cost of running the FGD but also because Chinese power stations pay a pollution charge for SO_2 emissions. We include this pollution charge in operating costs, based on figures for the charge per kg SO_2 emitted taken from (Xu, 2009). No credit is given for the desulfurized electricity price premium also mentioned by Xu.

Coal washing is increasingly used in China - the cost is invariably included in PDD baseline cost analyses. You and Xu (2010) gives figures for the capital and operating costs of coal washing – we add these to coal costs, calculating the annualized capital charge for the washery using the same capital charge rate as a power plant. Heat content of coal is adjusted for the loss in volume due to ash reduction. As we base our calculations on the ash content of washed coal, we effectively give credit for the reduction in railfreight achieved by washing. We take no account of either emissions or net revenues due to burning washery rejects.

The CO_2 emissions factor for coal is the IPCC default value for other bituminous coal.

A2.2: Coal cost and quality

Our analysis is based on all Chinese plants using Shanxi mixed coal with a GCV of 5000 kcal/kg, which is a standard blend supplied to thermal power stations. The China Energy Databook (http://china.lbl.gov/databook) indicates that coal from the state of Shanxi accounts for by far the largest proportion of coal transported across state boundaries.

There have been a series of changes in recent years in the pricing of coal supplied to thermal power stations by Chinese mines. Until 2007, coal mines used a dual pricing system: planned volumes were sold at low prices set by the national planning process while any production in excess of the plan quantity was sold at a freely negotiated price (usually referred to as in-plan and out of plan volumes). Sagawa & Koizumi (2007) show a breakdown of coal prices into in-plan and out of plan for years up to 2006 (Sagawa and Koizumi, 2007). The China Energy Databook gives the weighted average as an average price for all major state-owned mines.

After 2007 coal prices were liberalized – in practice the price became a weighted average of spot-based pithead prices and negotiated long term contract prices. Data for these years are unobtainable – our estimates are based on the following assumptions:

- We estimate weightings based on news sources including China Coal Monthly, Sinocast, Interfax, Coal World, China Coal Newsletter and China Coal Report.
- Contract prices for 2008 and 2009 are given in the same publications: for 2007 we take the in-plan / out of plan differential from Sagawa & Koizumi and apply it as if the contract price in that year is the in-plan price.
- Spot-based prices are based on FOR (free on rail) spot prices at Qinhuangdao (the key coal port) taken from the sources mentioned above and netted back to the mine using rail freight rates from Meier (2003) adjusted for inflation.

Meier's figures for delivered cost of coal to locations in Hunan (Central China) and Zheijiang (Eastern China) include freight and handling costs, stated separately. We adjust these figures using information on rate changes from the news sources mentioned above and generate freight costs for locations not included in Meier's calculations by assuming that they are proportional to distance. Judging by numerous news items, sea freight seems to have remained roughly constant over the period with a peak in 2007 followed by a decline (supplies to South China and much of East China are assumed to go by sea from Qinhuangdou). The sea freight rate doubled at the end of 2009, but this is outside the period of the analysis.

A3: RENEWABLE GENERATION

Cost and efficiency data for renewable generation projects in both India and China are taken from project PDDs. The only important assumptions that have to be made are those necessary to convert capital cost into an annual capital charge, and the estimation of costs of intermittency.

The annual capital charge is estimated using Stauffer's model. Key assumptions are:

- For China we used a 40 year plant life for all technologies: for India, the assumed plant lives are 25 years for wind and 50 years for hydro.
- Financial assumptions for India are based on levels permitted by CERC unless there is a reason to prefer a different figure –some regulatory parameters seem generous. The debt ratio (debt to debt plus equity) for renewable energy projects is taken as 70%; debt interest rate is 13% (rate permitted under CERC tariff regulations); tax rate is 34%; WACC is 15.6% - this is the rate permitted by CERC, taking account of a tax holiday offered by the Indian government as an incentive for investment in renewable energy.
- For China, debt ratio is taken as 50%; tax rate is 33%; interest on debt is 10%; weighted average cost of capital (WACC) is estimated by taking the assumption for coal fired plants (8% WACC and 70% debt ratio) and re-estimating WACC for the 50% debt ratio using the procedure described in (Brealey et al., 2006). With the

exception of the lower debt ratio for renewables, all parameters are as allowed by the Chinese government (according to several PDDs).

The cost to grid operators of wind (and solar) intermittency can only be established by means of a complex simulation exercise for the whole transmission grid. So far as we are aware, no such exercise has been undertaken in any developing country. A review of fifteen European and US studies (Holttinen et al., 2009) shows that integration costs per MWh increase with the proportion of supply to the grid contributed by wind, though no simple relationship is apparent. Many of the fifteen studies focus on the impact on costs of high levels of wind contribution to total generation – in several cases they show the impact for a range of contribution levels above 10%. For India as a whole, the contribution level in 2009 was 2% (IEA, 2011): by extrapolating curves of cost vs wind contribution given in Holttinen et al back to 5% we obtain a median cost impact of about $1.3 per MWh. We use a figure of $1.5 per MWh, which is conservative.

Abbreviations and Acronyms

The large infrastructure of organizations, treaties, emissions trading schemes and offset schemes that has developed since the creation of the IPCC in 1988 has given rise to a long list of abbreviations and acronyms - it is sometimes hard to believe that these strings of letters are not deliberately designed to confuse outsiders. I provide below a partial list of abbreviations and acronyms used in the document.

AAU	Assigned Amount Unit: Kyoto emissions caps are set in AAUs. Can be traded. (section 2.2)
BOCM	Bilateral Offset Crediting Mechanism: a NMM scheme proposed by Japan.
CDM	Clean Development Mechanism. (section 2.3.1)
CER	Certified Emission Reduction: certifies that a CDM project has cut emissions by 1 ton. Can be traded. (section 2.2)
COP	Conference of the Parties (signatories of the UNFCCC). COP/MOP (or CMP) means a COP that is also a Meeting of the Parties to the Kyoto Protocol. COPs are held annually in December and are numbered: for example, the Copenhagen conference in 2009 was COP15.
CPA	CDM Program Activity (section 3.2.8)
DNA	Designated National Authority – authorizes CDM projects (section 2.3.1)
DOE	Designated Operational Entity – specialized consultant that verifies CDM projects (section 3.1.2)
EB	The Executive Board – decision making body of the CDM (section 3.1.2)
ERU	Emission Reduction Unit: certifies that a JI project has cut emissions by 1 ton. Can be traded. (section 2.2)
EU ETS	The European Emission Trading Scheme (section 2.2.2)
EUA	Emissions permit in the EU ETS (section 2.2.2)
GCF	Green Climate Fund (section 2.6)
GCV	Gross Calorific Value: a measure of the energy content of a fuel
GEF	Global Environment Facility (section 2.7)
GHG	Greenhouse gases
GIS	Green Investment Scheme (section 2.4)
ICE	Intercontinental Exchange: a group of (mainly) commodities markets. Owns ICE Futures Europe (formerly ECX), which is the world's principal market for trading in

	carbon offsets
IEA	The International Energy Agency
IPCC	The Intergovernmental Panel on Climate Change – (section 2.1)
JI	Joint Implementation – a carbon offsets scheme (section 2.3.2)
JVETS	Japanese Voluntary Emissions Trading Scheme (section 2.2.3)
KC	Kyoto Credit – generic term for offsets created by the Kyoto Protocol – primarily CERs and ERUs
LCOE	Levelized Cost of Electricity (section 4.2.3)
LRMC	Long run marginal cost: the cost of increasing output by one unit after manufacturers and associated markets (e.g. labor, materials) have adjusted to changes in the product market
LULUCF	Land use, land use change and forestry (section 2.3)
MAC	Marginal abatement cost: the cost of reducing emissions (of any pollutant) by one unit
MRV	Monitoring, Reporting and Verification
MW	MegaWatt (10^6 Watts): a unit of generation capacity. GW (GigaWatt) = 10^9 Watts and TW (TeraWatt) = 10^{12} Watts
MWh	MegaWatt hours: a unit of power generated.
NAMA	Nationally Appropriate Mitigation Action (section 2.5)
NGCC	Natural gas combined cycle: a highly efficient type of natural gas fuelled generation unit
NMM	New Market Mechanism (section 3.3)
NZU	New Zealand Unit – emissions permit in the New Zealand cap & trade scheme.
OTC	Over the counter: off-exchange market for customized securities
PCF	Prototype Carbon Fund (section 2.3.1)
PDD	Project Design Document (section 3.1.2)
PoA	Program of Activities (section 3.2.8)
PV	Photovoltaic: Solar PV is a type of solar generation technology
REDD	Reducing Emissions from Deforestation and Forest Degradation – a UN-sponsored program to generate offsets. REDD+ is similar but places more emphasis on conservation
RGGI	Regional Greenhouse Gas Initiative: Emissions Trading Scheme set up by States in the North East of the US. (section 2.2.3)
RMU	Removal Unit – a credit issued when a ton of CO_2 is removed from the atmosphere

	by a carbon sink (typically a forest). Not eligible for the EU ETS and therefore rarely seen.
SA	Sectoral Agreement
SCM	Sectoral Crediting Mechanism: NMM based on emissions targets for whole sectors, not individual projects – a type of SA.
UNEP	United Nations Environment Program
UNFCCC	United Nations Framework Convention on Climate Change (section 2.1)
VCS	Verified Carbon Standard – body that assesses voluntary mitigation projects (section 2.2.3)
WCI	Western Climate Initiative: ETS set up by California and four Canadian Provinces.

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